COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	)
Preparation of the 2005 Integrated	) Docket No.
Energy Policy Report	) 04-IEP-01D
	)
Re: Clean Coal Technology and	)
Electricity Imports	)
	)

VOLUME I of II

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, AUGUST 17, 2005

9:06 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

Joseph Desmond, Chairperson

Jackalyne Pfannenstiel, Vice Chairperson

ADVISORS PRESENT

Michael Smith

STAFF and CONTRACTORS PRESENT

Kelly Birkinshaw

Marla Mueller

ALSO PRESENT

Steve Larson, Executive Director
California Public Utilities Commission

Doug Larson, Executive Director
Western Interstate Energy Board

Steve Ellenbecker, Energy Advisor
Wyoming Governor Freudenthal's Office

John Nielsen, Energy Program Director
Western Resources Advocates

Stuart Dalton
Electric Power Research Institute

Ron Wolk
Wolk Integrated Technical Services

Alex Farrell
University of California Berkeley

Larry Myer
Lawrence Berkeley National Laboratory

ALSO PRESENT

Joe Strakey
National Energy Technology Laboratory
United States Department of Energy

Steve Jenkins
URS Corporation

Ashok Rao
University of California Irvine

DeLome Fair
GE Energy

Kevin Taugher
Alstom Power

John Galloway
Union of Concerned Scientists

William Keese
Western Governors Association CDCC

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P R O C E E D I N G S

9:06 a.m.

MR. BIRKINSHAW: Good morning, everyone. First of all, let me introduce myself, I'm Kelly Birkinshaw. I manage environmental research for the Energy Commission.

I have just a couple of housekeeping matters I'd like to everyone through before we get started. And provide an opportunity for the dais to make some opening remarks.

First of all, please, if you keep your badge with you, if you leave for lunch you'll need that to get back in. And you'll need to check in with the security guard if you'd like to go up to the second floor for coffee; there's a small snack bar up on the second floor.

This is being webcast and so those that are participating over the internet will have an opportunity to speak and ask questions during the open discussion periods. We anticipate having an opportunity for questions after each of the speakers or panel sessions. And we'll be opening the phone lines at that time for you to ask your questions. Otherwise it'll be on listen-only.

I think that really concludes all of

housekeeping, and so before I introduce our first set of speakers I'd like to open it for opening remarks.

PRESIDING MEMBER GEESMAN: Thanks, Kelly. This is the 52nd day of workshops for the California Energy Commission's Integrated Energy Policy Report. I'm John Geesman, the Commission's Presiding Member of the Integrated Energy Policy Report Committee. To my right is Joe Desmond, the Commission's Chair.

To my left, Jim Boyd, the Second Member on the Integrated Energy Policy Report Committee. To his left, his staff advisor, Mike Smith. To Mike's left, Jackalyne Pfannenstiel, the Commission's Vice Chair. And to Jackie's left, Steve Larson, the Executive Director of the California Public Utilities Commission.

State law has the Energy Commission conduct an Integrated Energy Policy Report process every two years. This is the first time that we've gone through a full two-year cycle. We issued a report on an abbreviated timeframe in 2003. Today's workshop is intended to inform our review of different technologies, different supply strategies for the State of California.

The Committee intends to release a draft Integrated Energy Policy Report around September 8th. We will hold hearings on that draft report in early October, and bring it in front of the full Commission for consideration in early November.

With that, Commissioner Desmond.

CHAIRMAN DESMOND: I'd just like to welcome everyone here today for this workshop. Obviously the issues that have been raised in the IEPR are critical to California's energy future. I'd like to thank everyone for taking time from their no doubt busy schedules.

As Commissioner Geesman points out, the 52nd day. And so I want to give a special thanks to my colleagues, Commissioner Boyd and Commissioner Geesman, for sitting through all of these workshops. And it'll be four days this week, in fact, so they're getting quite adept at doing this.

Very interested in this information. Obviously we will have transcripts available of the information presented here for those who are not available, or after-the-fact, would like to see this. And obviously information presented on the web.

So I look forward very much to an informative day. We had two excellent days early this week on nuclear power issues, and now moving into clean coal options. Thank you.

CHAIRPERSON DESMOND: Commissioner Boyd.

ASSOCIATE MEMBER BOYD: Thank you. And I'll just add my welcome to all of you and my thanks to those of the others for your participation. Commissioner Geesman and I are molded to these chairs, we spend a lot of time here as indicated.

But I see a light at the end of the tunnel, Commissioner Geesman. I believe this might be our last subject matter hearing before we go on the road with our draft report.

In any event, as indicated in the notice, we have interest in the subject of electricity generated by coal. As a state we were blessed with not having, virtually none, generated in our state. But we're quite cognizant of the fact that we're dependent on the western grid and we're dependent on the import of electricity in our current and future electricity plans. And some of that is generated by coal.

Being a very environmentally sensitive state, we need to pay attention to the subject of how we procure the services that we need in the state, including our electricity. And we need to be cognizant of the fact that we may be sharing pollution with others just to meet our own economic needs.

And so Commissioner Geesman and I saw the need to look into the subject. And we look forward to adding to the Integrated Energy Policy Report views that we pick up and learn today, as well as some maybe policy recommendations regarding this subject.

And certainly glad our partners in the state's Energy Action Plan, the PUC, are with us here today on this subject, since they guide the procurement process.

So, thank you, and I look forward to the workshop over the next day and a half.

CHAIRPERSON DESMOND: Commissioner Pfannenstiel.

VICE CHAIRPERSON PFANNENSTIEL: I've been fortunate in that I have not spent all of the past 51 days in this chair. But while the scope of the Integrated Energy Policy Report is quite broad and needs to be broad, I think that there are parts of it that are immediate here and now, parts of it that we really need to get our minds around and our brains around, as we're developing longer term policy for the State of California.

And this, the subject today, I think is in that category; something I think we all need to understand better. There is, I believe, a lot of technologies that we need to understand and be willing to make some decisions on.

The policy report is intended to advise and to guide the state. And this is an opportunity for us to understand what that means and what choices we have going forward.

So, I'm looking forward to today -- the day and a half of hearings. Thank you all for being here.

CHAIRPERSON DESMOND: Mr. Larson.

EXECUTIVE DIRECTOR LARSON: Thank you, Mr. Chairman. It's a pleasure to be here representing the PUC.

This particular issue is one of great interest to the PUC. The Commission does not have a policy, to date, on coal, but we certainly have done a lot in terms of greenhouse gas reduction, and this certainly is a vital part of that.

And through the Energy Action Plan which established loading order through the Governor's statewide greenhouse gas reduction targets, and also through the draft of the Energy Action Plan II, there are all sorts of actions and strategies that have been outlined that the PUC is certainly very interested in pursing.

So this is a very important part of where we go from here. And we're very pleased to be here and thank you very much for giving us the opportunity to participate with you.

CHAIRPERSON DESMOND: Kelly, it's all yours.

MR. BIRKINSHAW: All right, very good. Well, before I introduce our first panelist, I'll just make a few comments about how we've organized and what we're trying to accomplish over the next day and a half.

California literally made a major transmission to natural gas over 30 years ago. And coal really hasn't been a major factor in our generating mix for a very long time.

Clearly, you know, as natural gas markets become more competitive, as we become more integrated in the western grid, there are opportunities that we need to be aware of and to make sure that those opportunities are examined and appropriate policies put in place here at the Energy Commission.

Because coal really hasn't been on the radar screen our first day is more organized around just foundational information. What we're going to try to do over the balance of the day is talk generally about coal technologies, characteristics, some of the opportunities as well a challenges to developing coal, particularly in the western United States for supply here to California.

Tomorrow's session is more policy oriented. Hopefully building upon what we learned today there will be an opportunity for individuals and other stakeholders to comment on policies that might be adopted by California really relative to our environmental stewardship as we look at generation options into the future here in California.

With that I guess I'd like to introduce our first three panelists who will be speaking generally about the western energy outlook and the potential for clean coal technology.

I'm going to introduce all three of the speakers just more for efficiency sake, and have them assemble at the end for questions in a panel setting.

Our first speaker is Doug Larson; he is the Executive Director of the Western Interstate Energy Board which deals primarily with energy issues affecting the western United States. The Board serves as an arm of the Western Governors Association.

Our second speaker is Steve Ellenbecker. Mr. Ellenbecker currently serves as an energy advisor to Wyoming Governor Dave Freudenthal, and is a consultant to the Wyoming Infrastructure Authority.

And then our third panelist is John Nielsen. John Nielsen is an Energy Program Director of the Western Resources Advocates, which is a nonprofit environmental law and policy organization.

His work focuses primarily on developing policies to promote clean energy technology across the west.

So, with that, I'd like to turn it over

to our first speaker, Mr. Larson. Thank you.

MR. LARSON: Chairman Geesman, thanks very much for the invitation, and also to -- not Chairman, Presiding Officer Geesman and other Commissioners.

Again, I'm Doug Larson, Director of the Western Interstate Energy Board. It's an association of 12 western states and three western Canadian provinces. The governor or premiere appoint a member of the board. We serve as the technical energy arm of the Western Governors Association.

My task is to help set the stage for the following discussion by painting somewhat of the big picture. So let me cut to the end. The concluding message is the buyer power will decide what generation is built. The CEC should consider more than just coal to electric generation. And we need to close the gap in the west in gasification technologies.

Now, I'm going to reach these conclusions by reviewing the generation mix in the western interconnection and how it's changed in recent years, providing some data on the western coal resource base. Listing a range of clean coal technologies; all are significantly cleaner than the existing fleet of coal generation. The fault line in the policy debate over new coal technologies is whether they provide for the capture of carbon dioxide and the sequestration of such.

Then I want to focus again on my message, that the buyer decides what gets built. I'll suggest some clues as to the type of generation that buyers want in the west, and how western load-serving entities are dealing with carbon risk, which is the major issue associated with coal.

I want to say a few more words about the suggestion that the CEC look at more than just IGCC technologies, and suggest that a task for all the west is to close the coal gasification technology gap that exists between eastern bituminous coals and western sub-bituminous coals.

This map shows the three interconnections in the west; for all practical purposes California's market is the western interconnection. Now, unlike ERCOT and the eastern interconnection, the western interconnection has enjoyed some vast diversity of generating resources in its subregions with extensive hydro in the northwest, significant coal production in the Rockies, a mixture of gas and nuclear in Arizona and the west coast states, and some renewables in California. However, this diversity has diminished in recent years.

This slide shows the generation mix in the four subregions of the western interconnection in 1998 and 2005. What's noteworthy is that every subregion has built almost exclusively natural gas in the last seven years. The diversity of generation in the west that we've relied on to lower prices is diminishing. You'll also note that very little coal has been added during this period.

This is the demonstrated coal reserve base in the U.S. Two points derive from this. One, it's really large. In the west it's 240 billion tons. By contrast we mine a little bit over 1 billion a year in the U.S.

Unlike the other point to draw from this graph is that unlike interior and Appalachian regions, the western coal resource base is primarily sub-bituminous coal. This is important to know, since very little coal gasification technology development work has been done on sub-bituminous coals as compared to bituminous coals.

This is a list of the advanced coal technologies being examined by the Western Governors Clean and Diversified Energy Initiative. Bill Keese, who's on the panel tomorrow, will be describing that initiative.

These Western Governors discussions have highlighted a fault line between the diverse interests participating in the initiative. And that fault line is whether technology can concentrate a stream of carbon dioxide that can be sequestered in geologic formations. I think Larry Myer is going to be adding more on sequestration opportunities later today.

Now, let me shift to my first method which is the buyer of the power will decide what gets built. This slide provides some insight into the 11 major load-serving entities in the west, at least 11 of the, what they're thinking about in terms of resource acquisitions. The information here was derived from some work that Lawrence Berkeley Lab did at the request of the Western Interstate Energy Board's committee on regional electric power cooperation.

We've added some additional information from Public Service Company of New Mexico that was available after LBL did their initial work. These are resource plans that were developed by these load-serving entities between 2002 and 2005. And while they represent only about 25 percent of the load in the interconnection, they do provide some clues as to what buyers are thinking about.

The graph shows nameplate capacity of resource additions expected by 2013. Black is coal. Most of the plans are still -- still include large amounts of gas-fired generation combined-cycle peaking plants. But recall that a lot of these plans were completed when gas was a lot less than its $8 or $9 it is today.

This slide shows the optimism over gas prices that's reflected in many of these utility resource plans. And I've added to it the most recent information from NYMEX. The takeaway here is that the load-serving entities are anticipating much lower gas prices than what the market is anticipating, at least in the near term.

Several of these load-serving entity resource plans explicitly examine the risks associated with future controls on carbon emissions.

Of those who considered carbon, some included a single number to reflect the risks of future carbon controls. Others, such as Idaho Power and Portland General Electric, looked at a range of carbon prices, used some weighted average when making resource selections.

Pacific Corp looked at a range of carbon costs and selected a number. Colorado Public Service or EXCEl, as it's now known, entered into a stipulation agreement with parties in a ratecase, or in a resource acquisition case, that, in fact, defined the number that that company will use in the future to weigh resource options. And John Nielsen, who is the third person on this panel, was a party to that settlement and can add more.

The point is that a number of load-serving entities are considering carbon risk in their selection of future generation resources.

Again, these assumptions are important because it's the buy who decides what gets built.

My second message is that when examining coal technologies, the CEC should consider more than gasification of coal for electric generation.

Because the IEPR process is intended to be an integrated assessment of California's energy needs, the CEC should consider polygen technologies that use gasified coal to produce both liquids and chemicals, as well as electricity.

This is done by running the coal gas through a Fischer Tropsch process that can generate a number of products, including clean diesel fuel. And part of the stream of the gas that emerges from the gasifier can be used in a combined cycle plant to generate electricity.

A lot of analysts, many analysts believe that this polygen approach to coal utilization is the most economic use of coal in gasification applications. This conclusion is, I think, being reached in the analysis being done by the Western Governors Association clean coal task force.

I'd also suggest that CEC examine the concept of integrating wind and IGCC into an ICGG system. To my knowledge the economics and technical feasibility of this concept has not been explored. It would have the advantage of making greater use of the transmission system than wind could, alone. And this is particularly important when we're talking about justifying investment in long-distance transmission where, from coal- and wind-rich areas to load centers.

As a side note here, some of the west's best wind resources are co-located with some of the west's lowest cost coal resources.

A second advantage, of course, is that this kind of combined product may have appealed to buyers because it is a much lower carbon content.

The next two slides are trying to illustrate this concept. When the wind is blowing, the electricity from the wind farm fills the transmission line, the gasifier is running 24/7, but it will store the product. Could be in a liquid form or a gas form. The CO2 from the gas fired could be sequestered.

When the wind's not blowing the product in the gas fired could be used in the combined cycle plant, again to fill the transmission system. There are lots of potential permutations of this idea, including the sale of some of the excess liquids that could be generated.

My final message is that the west has a collective interest in closing the gasification technology gap for sub-bituminous coal. The federal R&D on gasification has focused mainly on eastern and midwestern bituminous coal in plants that are located at low altitude.

This focus is the product of 20 years of concerted lobbying by easter interests, and aggressive policies by Appalachian and midwestern states that were losing market share to western coal. The recently enacted energy legislation that might help rectify this imbalance. It authorizes financial support for an IGCC project using western coals at altitudes above 4000 feet.

Last week Excel announced it was engaging EPRI to evaluate the economics of such a plant.

So, let me conclude where I began. The buyer of the power decides what gets built. The CEC should consider more than just IGCC technology. And the west needs to close the gap on gasification technologies.

Thank you very much.

PRESIDING MEMBER GEESMAN: Kelly, do you want to take questions now?

MR. BIRKINSHAW: Actually, what I would like to do is to have the panel --

PRESIDING MEMBER GEESMAN: Okay.

MR. BIRKINSHAW: -- is hold questions for all three panelists at the end.

PRESIDING MEMBER GEESMAN: Great.

MR. ELLENBECKER: Good morning, Commissioners, Staff, Executive Director, I'm happy to be here as an Ambassador for Governor Dave Freudenthal in Wyoming, and the Wyoming Infrastructure Authority.

I spent a year as an energy advisor to Governor Freudenthal; on his staff now as a consultant to him; and had a 30-year career on the Public Service Commission, the utility regulatory agency in Wyoming, and served as Chair the last ten years in that great career opportunity.

My message will have a public policy focus that I hope is of value to you as you consider technology today, and again, public policy tomorrow. I want to help set the stage and ask you to make some specific considerations along the way.

Perhaps never before is our potential for energy resource partnership, even in view of the physical distance between us, California and Wyoming, more relevant and good public policy. The intermountain west is full of abundant supply of relative low-cost, diversified energy resources.

As you make your public policy decisions here in California I ask you to consider technical and economic feasibility, and reliability of supply as part of your decision matrix.

Wyoming is number one overall energy producer in the country, number one in coal production, number three in natural gas, number six in oil and generates 300 megawatts of wind, along with the future potential of our world class wind resources, often adjacent to coal reserves, as has been mentioned by Doug Larson.

We have hundreds of years of fossil fuel supply available for future development. And I'm happy to be here as part of your decision making process in how to best possibly utilize that great resource.

With today's market prices for natural gas, Wyoming's proven reserves of natural gas and the production potential that we bring to the table have already made us a critical partner in energy with California by way of the Kern River pipeline, for example. I believe it's prudent that we expand this partnership for clean coal and renewable technologies.

The state geologist in Wyoming estimates we can increase our natural gas production 50 percent and extend that over a period of 40 to 60 years. We can continue as an important partner for natural gas production. And we have the wind resource capability, and then the clean coal technology potential by way of our vast resources to expand our partnership based on resources.

The gasification of coal to synthetic liquid fuels, natural gas and transmission and transportation fuels present a huge domestic supply opportunity for clean, abundant, secure supply, if only developed.

In 2003 then Governor Leavitt in Utah, Wyoming Governor Freudenthal were frustrated over the lack of integration transmission and resource planning in the west. They set in motion the Rocky Mountain Area Transmission Study, which led, after a year worth of stakeholder involvement, perhaps similar in part to the stakeholder process that I applaud here in California, it led to the recommendation for three 45 kV line upgrades in the intermountain west. Accompanied by an even larger project proposal, two potential 500 kV line and beyond, project proposals for expanding the resource base and delivery of electricity to the west coast states.

The RMATS study, with the intermountain build and the export model, suggest that the overall public benefits and cost savings to consumers are cumulative and only increase as you build out the intermountain grid alongside exports to the west coast states.

Combining up to 6000 megawatts of wind and baseload coal as a partnership resource base. Total annual net savings to consumers in the west are projected to be in excess of $1 billion per year, according to the RMATS analysis.

As byproducts of the RMATS study the Wyoming Infrastructure Authority, a statutory authority in Wyoming, assigned the duty of building transmission by way of advocacy and public policy recommendations in our state, not ownership but policy recommendations.

We have initiated, through the Infrastructure Authority early stage partnerships, to pursue three 45 kV expansions west out of Wyoming toward Boise, the Wasatch front range Salt Lake City, the Colorado front range. So north and westerly transmission upgrade project proposals to develop the intermountain west.

Each of these project proposals, combined with the Frontier line export proposal that would reach the west coast states, calls for approximately a 50/50 split between renewables, notably wind, and a coal resource base.

I refer you to the Rocky Mountain Area Transmission Study. You can get information and access to that public report by a search on the web. And to frontierline.org for information on the Frontier line project proposal.

It's not about whether it's possible to do these large western transmission and supply resource projects, it's whether we choose, as a matter of public policy, to do these projects. In my view, baseload abundant inexpensive coal is the best public policy strategy by which to maximize getting the accompanying renewable resources to markets on the same transmission line.

One won't work without the other in sufficient quantities due to the intermittency of the renewables that you're well aware of generally, and the unacceptable nature of coal resource without cleaning its characteristics significantly compared to existing pulverized coal technologies in the field.

Renewables as partners will help clean coal resources, as will advanced coal technology deployment and development.

I think it's odd and unfortunate that renewable and fossil constituents respectively seem mostly at odds with each other. Whereas the opportunity is to merge and marry these resources on the same transmission line for economy of scale and resource availability scale to fill the transmission lines, meet demand reliably with a diversified western resource mix. That's what I urge you to consider as part of your energy policy strategy.

If California public policy favors gas, if gas is available, let's work together on gasification technologies for electric generation, in combination with liquid fuels production to address both your electric demand needs with clean resources and your transportation and other liquid fuel needs with synthetic clean resources.

The Western Governors Association Clean and Diversified Energy Initiative is working toward this object to identify 30,000 megawatts of clean, integrated, diversified resources for the west, with a target of 2015, combined with dramatic improvement in energy efficiency

We appreciate California's strong contribution to that WGA initiative, and anticipate that that report, too, will support the general philosophy of our integrated policy recommendations and opportunities.

There's no time to waste, as you know. Reserve margins are down, demand is up, natural gas prices are up, gas reserves are down and declining, and coal-fired generation plants last a near lifetime. Our strategy ought to be to make certain that the next generation of those facilities are the cleanest facilities possible, because they truly do last nearly a lifetime.

I would ask you to tell us what resources you want, what type, what criteria emission limits you want, what carbon sequestration levels you want as public policy. Incumbent with that is the offer to pay for that resource technology as part of the necessary equation to get the resource delivered.

And help us with the west regionwide policy, and transmission expansion policy needed to get these abundant diversified resources to markets both in the intermountain states and on the west coast to meet your dramatic demand growth.

Various resource interest groups are still playing defensive strategy against each other, rather than offensive strategy together. RMATS and the Frontier line that have addressed our regional transmission and resource planning initiatives designed to bring renewables together toward the same common cause. I ask you to consider the same public policy initiative.

We desperately need a technology and commercialization strategy to break through advanced coal technology and put together plants before the next generation is built. I would hope that your public policy, in part, in support of clean coal technology, would present the demand opportunity to make the commercialization of those advanced technology plants possible.

We won't get it done without large-scale regional partnerships. Timing is all critical now before the next fleet is built in view of growing demand.

As Governor Freudenthal says, I've got

the energy resources, diverse, abundant, with a public policy in Wyoming which favors energy development in the state. I'd be happy to partner with you to enable your access to those resources. So tell us what you want, what the characteristics are, how much you need, help us build the regional transmission network and transportation network to accomplish the end of our production interests and your demand needs.

Frankly, once we decide on a public policy insofar as clean coal technology, so too, will there necessarily have to be a commitment, as well, to recover the costs of building and delivering that energy resource and its attendant costs as part of the same public policy considerations.

Ratemaking or IRP standards may have to be taken in a new realm with a new regional scope. Spreading the costs and benefits and risks and resource award across a broad spectrum geographically and with public interest, not on a state-specific, but a regional interest basis.

Without this transition and evolution in public policy thinking beyond states' boundaries or utility-specific service areas, intermountain and west coast policymakers are assuming the same defensive posture as are specific supply side resource advocates. And doing so is counterproductive compared with the diversified clean resource opportunity that otherwise lies ahead.

I, on a personal note, it's been particularly a pleasure to have the opportunity to work with the California Energy Commission on these important initiatives. And I appreciate the opportunity to represent Wyoming here, and some of the underlying regional initiatives that I believe are in progress and can be, in part, the solution to your energy needs in this state.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you very much, Mr. Ellenbecker.

MR. NIELSEN: Good morning, Commissioners. Thank you very much for the opportunity to be here today. What I would like to do is give you a perspective on clean coal issues from someone working in the environmental community in the interior western part of the country where much of the new coal development is being proposed.

I'm going to give you a little background. My organization, Western Resources Advocates, we are regional nonprofit; we work in the interior west. Our energy program promotes clean energy resources in the region. We have an interdisciplinary staff. We work primarily in state and regional forums, public utility commissions. We work with the legislatures in our states. We're involved in air quality permitting. We've worked with the WGC through the CDEAC process and also the Western Regional Air Partnership. We've been involved in transmission planning and we also work directly with some of the utilities in our region.

And we work closely with groups in California, Environment Defense, NRDC and CEERT. And our focus is electric power.

These are the key points, key message that I want to make today. The first one echoes, I think, one of Doug's points that markets are going to decide what kind of power gets built.

California markets and energy policy decisions in California are a, if not the, critical factor in determining whether genuinely clean coal technologies will play a role in meeting western energy needs.

I think emerging California policies are sending -- well, the promise of sending the right signals. The carbon reduction targets from Governor Schwarzenegger, the Energy Action Plan, the loading order that you've developed, the RPS, the PUC's energy savings goals, but those signals will need to be stronger and more clearly sent if we're really going to shift investments from conventional coal to clean coal technologies in our region.

So here's an outline of what I'd like to just touch on today. I want to give you some sense of the scale of the proposed coal development in the interior west; provide some information on the environmental impacts of the proposed new coal plants.

Talk a little bit about how I think, and this echoes, I think, one of Steve Ellenbecker's points, that the debate over coal is polarizing the broader regional energy debate. I think it's jeopardizing investments in other clean energy resources. And I think that focusing on genuinely clean coal offers an opportunity to depolarize the debate we have in our region, and move the broader clean energy agenda forward.

I want to provide some perspectives on what the definition of clean coal is from our perspective; and then talk briefly about what California can do to encourage clean coal development in the interior west.

So, this slide I hope gives a sense of the scale of the proposed new coal development in the interior west. We've seen 31 new coal plants representing about 18,000 megawatts of new coal-fired generation proposed in the region. Many of these are speculative; some are more real than others.

But about 16 plants, or 8200 megawatts, are currently actively going through the permitting process. And of these 16 plants, 12 of them are conventional subcritical technologies. There are two supercritical plants proposed; two circularized fluidized bed, CFB, plants proposed. And as of yet, no gasified coal plants proposed or going through the permitting process.

At least six of these plants are targeting the California market, about 5500 megawatts. And then economic viability of other proposed plants hinges on the ability to sell wholesale power into California.

An additional 6000 megawatts has been proposed as part of the Frontier proposal. And then these resources would be on top of roughly 4700 megawatts of coal that currently is owned by California utilities.

The environmental implications of these plants are large and they'll last a long time. If built, these plants will run through 2060, when our children's children are coming of age. If you look at just the 8200 megawatts of coal that is actively going through the permitting process, they would emit about 66 million tons of CO2 per year.

And to put this in perspective, by 2020, according to the recent study done by the Tellus Institute, estimates CO2 reductions from the Pavley Bill would be about 30 million metric tons of CO2 equivalent per year. The energy efficiency goal established by the PUC are about 8. And accelerated RPS is about 11. For a total of about 50 million metric tons. And so the proposed coal plants would essentially offset all of those CO2 reductions if they go forward as currently proposed.

And then beyond CO_2 the plants emit significant amounts of other harmful pollutants contributing to haze and ozone, nitrogen deposition, other air quality problems that we have in the interior west.

I think in a real way the debate over coal is really polarizing the energy debate in the west. Essentially all the proposed plants, as they're currently being proposed, are being challenged in air quality proceedings, siting proceedings, before PUCs. These proceedings tend to be contested; they tend to be adversarial; they tend to push stakeholders to take extreme positions. And they don't really foster kind of a problem-solving mentality.

And I think this polarization really does jeopardize other clean energy investments in the region. Steve mentioned the Frontier line, the opportunities to develop renewable resources there. I think that's representative of kind of a broader need to develop energy infrastructure to promote clean energy in our region.

But opposition to new transmission will be intense if it's built around new conventional pulverized coal because of the concerns of the environmental impacts. And I think this does threaten to foreclose renewable energy and other clean energy development in our region.

And, also, I think as Steve mentioned, I think everybody is in a position where they're playing defense right now. I think the environmental community is worried about opening the door to massive new emissions, particularly of carbon dioxide. I think the coal and utility industry is concerned that pushing toward clean coal is just a ruse to raise the price of coal and screen it out of energy markets.

And I think if we can focus on genuinely clean coal development, establish that it has a place as part of a clean energy future, we can take steps to depolarize this debate and move a clean energy agenda forward.

I want to give a perspective of what clean coal is from WRA's perspective. I think this is similar to other environmental organizations. We view modern IGCC technology as the benchmark for clean coal technology. And we would consider coal clean if the plant is capable of economically capturing and storing its carbon dioxide emissions. That the emission rates for other pollutants, such as NOx and SOx, criteria pollutants such as mercury are no greater than a modern IGCC plant with state-of-the-art pollution controls.

Water is a concern in the interior west. We would look at water consumption no greater than a modern IGCC plant. And we'd look toward siting opportunities where there are ways to use captured carbon down the line in an economically beneficial way, such as enhanced oil recovery, or to geologically sequester the carbon dioxide.

I want to talk a little bit about some of the barriers that we see at IGCC development. We do work with a lot of utilities in the interior west. These are some of the key things we hear back from them about why it's difficult to move to an IGCC benchmark technology.

First, it's cost premium relative to conventional coal. We hear anywhere from zero percent premium up to a 20 percent cost premium.

In a way I think even bigger than the cost issue is the perceived technology risk. We hear concerns that this technology may not work as expected, and that leaves power developers hanging if they need the power.

Doug mentioned we have a lack of experience with western sub-bituminous coals, with IGCC development. Concerns have been raised over operations at elevation. And I think a big barrier is no formal requirement to factor in carbon when making the technology decision.

So, a little bit about what California policymakers can do, I think, to help shift this debate. I do think that the emerging policies coming out of California have the potential to send the right signals. But they need to be stronger and more clearly sent to power developers, and I think folks outside the region, to have an awareness of what California is doing. That message needs to expand beyond state borders.

Particular reinforce and publicize the loading order. You've established that efficiency renewables and clean fossil are the loading order. And that sends a strong message that clean energy is a priority in California. And this policy needs to be made known more widely out of the state.

I'd look to have all power plants serving California load, whether located in or out of state, meet minimum environmental standards.

For coal plants, IGCC should be the performance benchmark.

Again, make clear that all imported power counts against California's carbon target. The signals that carbon must be factored into the technology choice.

Look for ways to partner with the supply instate to encourage IGCC or equivalent technologies. For example, to help narrow any cost premium, other opportunities to partner with supply side states who might provide financial incentives, tax relief, to reduce a premium. And the consuming states may cover that smaller difference.

We need to see an IGCC demonstration project in the west using western coals. To the extent that California can support that kind of demonstration project by encouraging its utilities to participate, I think that would be a big help.

And then I think on a last note, encourage and allow cost recovery for pollution control investments and possible repowerings of the existing coal plants serving California load. I think not only do we need to look forward and take a step to get cleaner coal technologies in place, but there's a lot that can be done to address the environmental problems associated with existing coal plants that are now sending power to California.

Thank you.

PRESIDING MEMBER GEESMAN: Thanks very much, John.

MR. BIRKINSHAW: We have a few minutes for some questions now for the panel.

PRESIDING MEMBER GEESMAN: Let me ask my colleagues if they have questions. Commissioner Desmond?

CHAIRMAN DESMOND: Thank you, and by the way, to all the speakers, very informative presentations. And I think correctly captured the challenges that we face here in the west in establishing policies that resolve the need to encourage more renewable energy, while addressing the environmental constraints that we face.

I want to ask a couple specific questions for clarification purposes, and perhaps these will be directed to Western Resource Advocates, with respect to the suggestion on the plant that's capable of economically capturing and storing CO_2.

And what I'm asking for is a clarification of what you mean by that definition. In other words, is the suggestion that is a prerequisite that there needs to be in place a system. I know it says capable. And is the cost effectiveness criteria meaning the economic associated with the capture technology, or the economics of the storage?

Because I think we're going to hear later today from other speakers on the cost of sequestration. And if you have any thoughts on that. So, and perhaps others weigh in.

PRESIDING MEMBER GEESMAN: You need to make certain the green light is on on the microphone. There's a button that says push.

MR. NIELSEN: Is that better?

PRESIDING MEMBER GEESMAN: Yeah.

MR. NIELSEN: We're looking at a definition that a plant would be capable of capturing carbon dioxide at some point in the future. And I think in terms of the economic question we're looking at it would be both carbon capture and the storage aspect of that. That would be factored into the economic calculation that we're looking at. Can you do that economically with that technology, both capture and storage.

CHAIRMAN DESMOND: Sort of a followup question. I know that there has been talk, and I think that Doug, in your presentation, you looked at the interesting aspect of the hybrid wind IGCC plant, also.

Any work or any efforts into the combination of biomass in concert with advanced coal technologies as a way of taking advantage of the sub bituminous coal?

MR. NIELSEN: I haven't seen work along those lines.

MR. LARSON: I haven't seen such work in the west. There's examples in the east where there's a larger biomass resource that can be coal-fired with conventional pulverized coal, but I haven't seen much of that emphasis in the west.

CHAIRMAN DESMOND: Okay. And last question. With respect to carbon on import, you're talking about all sources of carbon, meaning carbon associated with natural gas-fired generation, as well as with any other generation, is that correct?

MR. NIELSEN: That'd be right.

CHAIRMAN DESMOND: Okay.

PRESIDING MEMBER GEESMAN: Commissioner Boyd.

ASSOCIATE MEMBER BOYD: Yes, thank you. First let me thank all three panelists. And let me assure you you all had a message of appeal to us, so to speak. And your message certainly falls on friendly and interested ears here, I think as evidence by our work with you in other forums.

As Chair of the Commission's Natural Gas Committee, as well as Chair of the Transportation Fuels Committee, I'm going to ask a couple questions in that arena.

Doug, I was, of course, very interested in your polygen concept and gasifiers yield GTL. In our 2003 Integrated Energy Policy Report and our report of the same year on reducing dependence on petroleum, the state identified GTL as a potentially very advantageous adjunct to our fuel base.

And I'm wondering if -- and let me just say that so far our interest has been not well realized because all the GTL in the world is being produced somewhere else, not in the states. You know, it's a long way to Qatar or Qatar, call it what you want.

But the fact that gasification can provide GTL has been of interest to us and to me for quite some time. We've had many proponents come in here and talk about doing that with coal in the west, but frankly have not seen anything.

And I'm wondering if a very strong expression on the part of this agency in California in that liquid fuel subject would add anything to the momentum you say you need and the messages you need to get to put pressure on the idea of IGCC and that attribute.

Electricity aside, we need it, we need it clean. California, you know, the economic nation-state of California is nonetheless part of the western family of states, and part of the western grid. And so certainly electricity is a key need.

But I'm interested in the liquid fuel, as well as in Wyoming's natural gas. And a second question would be I know representatives of this agency in the past talked about it's good to develop Wyoming's gas. It doesn't matter where it goes; it can go east because it adds to the great body of natural gas.

I'm more selfish than that. And I'm curious as to the possibilities of sending Wyoming's gas west as far as California.

So, there's a couple questions wrapped up there.

MR. LARSON: Let me take the liquids question. I think it would be very productive to have California send a signal that we are interested in the development of gas to liquids from coal.

California has been a technology leader for decades now. And I think the development community takes a signal from that. Not to mention the sixth largest economy in the world, it burns a lot of fuel.

So I think it would be a very productive signal to send to developers that California is, in fact, interested in liquids from coal. And my understanding of that, you'll have experts later in the day, is that the production of, for example, clean diesel fuel from the polygen technology actually will aid in enabling refiners to meet sulfur standards, because essentially it's a zero sulfur product, that will help compensate for, you know, contaminations picked up in pipelines from conventional diesel that's generated in refineries.

So, I think it will be very productive stuff for California just to say we're very interested in developing liquids from coal.

PRESIDING MEMBER GEESMAN: Commissioner Pfannenstiel.

ASSOCIATE MEMBER BOYD: I think this gentleman --

PRESIDING MEMBER GEESMAN: I'm sorry.

MR. ELLENBECKER: Commissioner, briefly for Wyoming, same answer on the importance of California's message there. Some of the developers considering projects in Wyoming are looking seriously at the GTL technology and product, along with electricity production, as it relates to your second position and your key interest in natural gas.

I think the answer there goes to transmission grid, transmission infrastructure, whether it's natural gas or electricity. The opportunity to have access to the resource is inherent in the ability, whether it's natural gas, new technology from coal to liquids, and electricity through advanced technologies and renewables. Partial of the solution has got to lie in the grid or the transmission means by which we move that product.

And it sets the stage for you to have the vested interest, as public policy. But then be the recipient of the product by way of also expanding the partnership, not to just public policy on the resource, but getting it delivered.

ASSOCIATE MEMBER BOYD: Thank you.

PRESIDING MEMBER GEESMAN: Commissioner Pfannenstiel?

VICE CHAIRPERSON PFANNENSTIEL: Actually, an observation that the panelists may or may not want to comment on.

But I heard a couple times that the market will decide what gets built. But I would observe that the market will decide that correctly, I guess, if all the costs are internalized. And therefore you get the cost of clean coal internalizing to the cost of the coal and therefore the market is looking at the correct cost.

But I'm placing that kind of conceptually against there's an urgency that I heard about we really need to get going, but it's all dependent on this technology development.

And so I'm kind of still stymied at the technology development. I think it's pretty clear to people that there is a technology that is potentially economic, but needs to be further developed. But we don't want to run out and build the coal plant until we have the technology.

So, I'm just hoping that over the course of the next day and a half we'll hear more about what is the timing, what is the cost, when will these clean coal resources be available to us in California so that the market can, in fact, make that choice.

I don't know if there's a response to that, but that's how I heard this morning.

MR. LARSON: I just want to emphasize the technology will take time, time to evolve, you're correct. But for it to evolve there has to be very clear, consistent, long-term signals to market participants about what buyers want.

And in California the regulators -- and other states -- regulators circumscribe that portfolio resources. So the plea is to set very clear, consistent, long-term, sort of acquisition policies because especially for gasification technologies and a lot of other long-term technologies, if you don't set those and don't have them consistent for the long term, you're going to end up without that technology being developed. And the fallback will probably be gas-fired generation near load.

PRESIDING MEMBER GEESMAN: Mr. Larson.

MR. NIELSEN: I would --

PRESIDING MEMBER GEESMAN: Oh, I'm sorry.

MR. NIELSEN: I would just echo, I mean I think this message that the market will decide, consumers will have a say here, but I think what California and other states do to kind of set that public policy framework, set those market conditions, is going to be critical.

And, you know, Doug's message that a strong, clear signal from policymakers in California is critical.

PRESIDING MEMBER GEESMAN: Let me ask if there has been any evaluation done either by any of the individual western states or regionally on the water availability to support a large-scale development of the coal resource, either from a gasified standpoint or a pulverized coal perspective.

MR. NIELSEN: We've certainly done a look at the water use of the various technologies. I don't know if there's been a broad study done to look at available water for broad-scale coal development, but typically conventional pulverized coal technology will use about twice the water of an advanced IGCC technology.

And water scarcity is a critical problem, of course, in the interior west, which is an arid region. And it's a factor that's increasingly looked at in technology choice and siting decisions, is there available water. How do you minimize the water use from power production.

I think it's a critical part of the technology decision and the siting decision for these plants.

MR. ELLENBECKER: And, Commissioner, I would add in support of that, that I met with a project developer in Denver looking at a site for gasification in central Wyoming, a large project, combined with wind.

And they are driven to gasification as one of their decisionmaking criteria because of the reduction by 50 percent, or thereabouts, in their need for water, as well as their decisionmaking on cooling, a hybrid of including air and water. And they have designed, preliminarily, that project to reduce the water impacts.

Certainly your point goes to a very real issue that has to be dealt with. But if we are going to develop these resources, and I think we have to to meet the load demands in the intermountain states, and in the west coast states, these new technologies spoken of on your first panel, and I presume throughout the next couple of days, are the solution at least for mitigating the water needs.

PRESIDING MEMBER GEESMAN: Second question that I had was on the legal side. And I guess I have some concern about our ability as a buying state to discriminate against pulverized coal, particularly when you're relying on the high voltage transmission system to convey that coal or that electricity to California.

Are any of you aware of any legal analysis that has been done that would support our ability to specify an environmental requirement consistent with the Federal Power Act or the Interstate Commerce Clause of the Constitution?

MR. LARSON: I'm not. I just observed that the load-serving entity is the one signing the contract. And I don't think there's anything in the Interstate Commerce Clause that would tell them they have to buy generic power. So I assume the load-serving entity gets to make that choice. And to the extent you influence their decisions, you --

PRESIDING MEMBER GEESMAN: But if we build the high voltage transmission system necessary to convey that electricity, do we have any ability to discriminate against who uses it?

MR. LARSON: I don't think so. But, again, -- Steve, you may have a different take on this -- is major projects like the Frontier line are not going to be built solely on merchant transmission developers. They're going to want power purchase contracts with load-serving entities to make that project financially go.

And so, again, you're back to what does the power purchaser want to buy.

MR. ELLENBECKER: I share that opinion.

MR. NIELSEN: I think to the extent

that, for example, you had a policy where you were looking at carbon reduction targets, and you were counting out-of-state power toward those reduction targets, I think you can certainly set up a policy to count those emissions toward such a target. And any load-serving entity in the state would need to operate under that requirement. And I don't see a legal obstacle there.

PRESIDING MEMBER GEESMAN: Thank you very much. Commissioner Desmond.

CHAIRPERSON DESMOND: Yes, I had one followup comment in response to Commissioner Geesman's first question regarding water.

I believe that, in fact, there are some studies underway right now at the University of Montana that are focused on water reclamation from coal bed methane activities.

And the purpose of those is to identify the ability to create a reservoir and use that water for purposes of cooling. So, that's one study. I believe they're scheduled to present that in Denver in October at the annual energy economists convention.

The second is that there's also another process, coal beneficiation of processed coal, in which you're essentially using combined heat and power in order to extract the moisture content from the sub-bituminous coal. And that also provides a source of water which is also then used for cooling those coal plants.

So, the combination of those, also in terms of the reason I asked about the biomass, is the soil reclamation that can be used, when mixed with this coal yielding the carbon profile as a high efficiency, combined cycle natural gas.

And so there is work now underway in a number of locations to begin to explore what I'll categorize as a systems approach to this, that really begins to integrate the renewables component maximization of wind, the water issues, and the carbon capture from a holistic perspective, if you would.

So, just want to add that to the record.

ASSOCIATE MEMBER BOYD: One final, if I might, comment. In response to the biomass comment, question that Chairman Desmond asked earlier, I had to think to myself that in reality there's an awful lot of biomass fuel in the western states. We just haven't taken the time. And even California has struggled with it, because it's cellulose. And we're still struggling to get a handle on that.

But there is a lot of fuel in the western states, certainly forest thinning, et cetera, et cetera. I don't want to cross the line into what's ecologically acceptable there.

But there's probably a lot of research potential in that arena, as well.

PRESIDING MEMBER GEESMAN: I want to thank each of you for your participation here. It's been very helpful to us.

MR. BIRKINSHAW: Very good, thank you very much, also. I think we're going to have to hold questions from the audience or from the internet till the public comment period this afternoon.

And so, with that, I'd like to transition now to the really more technology focused part of today's presentations, and introduce our next speaker, Mr. Stu Dalton, with the Electric Power Research Institute.

Mr. Dalton has been with EPRI since 1976, and has headed the sulfur dioxide control integration emissions areas. For the last ten years, has managed and developed strategies for broad areas of advanced coal and emission controls at EPRI. He is currently the director for the generation sector at EPRI. Thank you.

MR. DALTON: Thank you, Mr. Chairman, Commissioners, ladies and gentlemen, it's my honor to be here this morning talking about a subject that I've been involved in, literally up to my hips on occasion, for the last 30-odd years.

And a good part of that actually was in California, in the '70s, looking at the possibilities of coal plants in California. At the time they would have been the cleanest. It didn't happen. Megawatts happened, if you want to call it that, and conservation really ruled the day and the generation wasn't required.

But since then with the Electric Power Research Institute I've devoted a career to looking at cleaning up coal in different ways, in different applications in the west, the east, and around the world.

Coal is, as you know, still the predominate fuel for generation in the U.S. Over 50 percent of the generation today comes from coal. That percentage is not projected to go down by most estimates. While nuclear has increased, gas has increased, you can see that the overall generation in kilowatt hours has been dominated by coal.

But, as was said earlier, the dominating factor in new build in the last six years particularly has been gas, 205 gigawatts since 1998. And what we call this, these are our titles on this graph, the data, however, is from the -- adapted from the Public Utilities fortnightly, shows just what a dominant force gas has been in the generation mix over the last, particularly the last six years. True in California, as well.

You can see here that the big buildout in coal was in the '60s through the early '80s; and that there hasn't been a lot of coal built in the U.S. over the last decade.

Now, this is a slide that AEP put together to show what the EIA and the Department of Energy forecasts look like for future coal. That is a snapshot. You can see that there is a tremendous new upsurge in interest in coal primarily because of the price of natural gas, and the competitive nature of the marketplace.

What is coal is not an easy answer. It depends on where it comes from and what it had in it when it was laid down, geologically. Obviously one of the biggest elements in coal is carbon. Ash, typically rock, silica, calcium, other things that have come in there. Some of it's incorporated in the coal, some of it is laid down as part of the coal matrix.

Sulfur, a big contentious issue, blessed in the west with some of the lower sulfur coals, just the way they were laid down geologically. Nitrogen; oxygen. And nitrogen, of course, can be converted to oxides of nitrogen, one of the issues in coal combustion or any combustion for that matter.

Hydrogen, there is some in coal, though less than in oil, and even less than in natural gas. Mercury, huge issue, and literally the subject of one of the brand new EPRI journal articles on mercury that just came out. First time we've issued the journal in a number of years. The cover article is on deploying new coal, advanced coal plants. And I commend it for bedtime reading, at least, if you really have a hard time getting to sleep.

But we think it's a pretty good summary of some of the new deployment activities going on, as well as some of the mercury issues. Both on health and fate of mercury, as well as on how to capture it from coal.

And water. And in the west, while we're blessed with a lot of coal with low sulfur, it also tends to be higher in moisture. That'll come into play when we talk about gasification.

And I added something. You may have seen this sort of a picture before. In fact, it's right out of our article, but I added petroleum coke. Because in a very real sense petroleum coke, the bottom of the refinery where you made it into a solid, is an indigenous carbon resource in California.

Some of the oil comes from California, goes into the refineries, which then squeeze the barrel to get the top of the refined products, the gasoline, the jet fuel, the diesel fuel. What's left? Well, what's left after you squeeze it, and after you have added hydrogen from natural gas, it's converted; goes by pipeline to the southern California refineries. Squeezes that barrel; what's left is petroleum coke.

The reason I mention it is when you start to look at gasification, yes, that's true that gasification doesn't necessarily operate the same with a low sulfur coal, and not with a western coal with the high moisture. But if you add petroleum coke, you've got a different mix. And, in fact, many of the commercial gasifiers have operated with that sort of mix, including for extended periods of time. And it changes the economics. And displaces a current use for natural gas to make the hydrogen to go into the fuel.

I'll point out also that up in Washington State, you may have seen the announcement, the Energy Northwest Organization has recently said they're looking at gasification. But it's going to be western coal, plus petroleum coke. That particular coke comes typically from the Alaskan oils that are refined in Washington. They have some coke available. So it's an interesting nuance in the overall mix.

But I'll also point out two other things. The enormous reserves of Powder River Basin coal that are out there. These are really the -- it's actually more in energy terms than the Saudi Arabia of the U.S. There's more energy in the ground in Wyoming -- well, in the Powder River

Basin particularly, but in Wyoming, I believe, as well than there is Btu in the ground in Saudi Arabia. It's a tremendous resource.

There are also other resources in the west, including some with bituminous coal. Utah has some very high grade coal that's been used for coking. If you remember the Beehive State, that's because of the beehive coke ovens that used to make coke for steelmaking up through World War II. I think they've all closed down. But they're great landmarks.

Around the country there's a variety of coals. Some of the commercially significant ones are highlighted here with some words over them. The Illinois Basin, the Appalachian Basin are what people tend to call eastern coals. Lignite, an enormous resource. But it's not typically as concentrated as, for instance, Powder River Basin coals. But there's a lot of it.

Tell you a little bit more about what's in it. And if you just look literally at the bottom line, you can see that the lignites -- this happens to be a Texas analysis -- have about half the energy in a pound that a high-grade eastern coal does.

Western coal, specifically Wyoming Powder River Basin, which is a very very heavily commercially used coal in the marketplace, has some interesting characteristics. I'll point out the top line. It does have some moisture in it. I'll point out the ash content is relatively low down at the bottom. And the sulfur content is low.

And when you compare Texas lignite, for instance, with Wyoming Powder River Basin, typically the sulfur content is one of the things that's made it a dominant fuel in the marketplace. People have bought sulfur control by switching. Used to be that many of our members burned Illinois #6. Today none of them do. They tend to burn Powder River Basin coals. It's not quite Newcastle, but they are hauling the coal there.

The point is here that they vary widely. And I pointed out the moisture, I pointed out the heating content, those both become critical when you start to look at what different coals can do with different technologies.

This is a very simplified version of what is pulverized coal, or ultra super critical coal, or circulating fluidized bed combustion, or gasification. So a relatively simple definition. You finely grind to the -- almost to face powder -- the coal; burn it; raise steam; and clean the flue gases. Again, I spent most of my career on that cleaning the flue gases part.

And there are over 1000 such coal plants in the U.S. operating today. Many in the west.

The very high temperature versions of this tend to be super critical steam cycles. And even higher temperature have a jargon term associated with them, not a technical term, but a jargon term called ultra super critical. And that's not University of Southern California if you see it later in the presentation. And since I was a Berkeley guy, it's definitely not University of Southern California.

The circulating fluidized bed combustion is used for a number of unusual fuels, going to burn tires, chicken litter, what-have-you. You can burn it in the fluidized bed boiler. You can also burn coal in larger pieces because of the way it burns. They are fluidized, meaning moved, by air, combustion air, entrained, moved around, and typically a sorbent like limestone is added into the mix. And that helps capture some of the SO2.

Gasification is you're taking the molecule and you're breaking it apart. And then what you really do is when you want to make a liquid, you put them back together, after you've cleaned it up to a fare-thee-well.

Do you drink diet Coke, any of you, or use the sweetener that comes in the -- the Equal in the little blue packet? If so, or if you've used Kodak film, or if you've had a Stanley screwdriver in your tool chest, you've used coal. And probably didn't know it. Because the chemical intermediates that are produced by Eastman Chemical, they're very pure. They have to be to meet these food grade specifications, et cetera. And so you can clean up coal after it's been gasified to a fare-thee-well.

What you've done is you've made a synthesis gas, primarily carbon monoxide and hydrogen. These are the basic building blocks that can be put back together. There is some methane.

The gas is cleaned and burned in a gas turbine for integrated gasification combined cycle. And the exhaust heat is used to make steam. These are called IGCC plants. So that's the definitional primer part of the different types of coal generation.

But what does it mean to say clean coal? That is a debatable point. There's no absolute definition of it. What's clean enough? That is not a absolute definition. But most people would say refers to designs meeting very stringent emission regulations.

Coal-based IGCC plants have very low SO2 emissions, but they're set based on the exact requirements of the plant site. I believe, based on what I've seen of the preprints, that you'll see some of that controversy here in front of you on the podium. Not, per se, by me, but a number of people will be talking about the different emissions, possible or actual, from combustion and gasification plants.

We, the Department of Energy, CoUtilization Research Council, have developed some what we believe are goals for 2010, 2020. There is a roadmap for this available at www.coal.org. It's not our site. But these typically are very stringent emission goals.

This is also a bit of a controversial slide. We believe that the regional differences favor multiple advanced coal options. As I mentioned, and as others have mentioned, most of the work around IGCC has been done on so-called high rank or bituminous coals, which could include, by the way, the Utah coals. They have been used for purposes like this.

Or low rank coals plus petroleum coke. And there has been a lot of operation of the commercial units on those low rank coals plus petroleum coke. New IGCC designs may be better for these low ranked coals. There is a lot of work going on.

The one slide here that I have, I think i can use this, for the people on the internet I'm sorry, I'm going to use a pointer here -- shows a high-rise structure that's a test unit in Alabama that actually is going to be testing low rank coals and lignite. And this will be a demonstration in Florida. Under the clean coal program, the Clean Coal Power Initiative program of advanced gasification.

But the other picture is an interesting one, because this shows an operating 250 megawatt gasification plant in Indiana, and the power generation is a small portion of the overall plant. The rest looks very much like a refinery, because that's what you're really doing. You're refining the coal, you're breaking apart the molecule, putting it back together and refining it in a way that -- cleaning it up, really, and then burning the gases. But it looks like a refinery. Oxygen plant, sulfur removal and cleanup of all the other streams.

Supercritical fluidized bed has not been built yet. It's saying that the fluidized beds tend to be lower efficiency and smaller in size. Waste coals, biomass may be best suited there. I will add, relative to the earlier question on biomass, that the Buggenum plant in the Netherlands indeed used quite a bit of biomass. And they have a requirement for percentages of biomass to be used in the future. It used chicken litter, I believe, is the polite term, as one of the materials. That's IGCC, I'm sorry.

But the fluidized bed boilers can burn virtually anything. And they do in California, as well, I believe, have a number of fluidized bed burning many different things.

U.S. plants tend to be these conventional plants because the economics have been relatively cheap coal in the U.S. Now, there have been some increases in coal prices over the last couple of years. But in Japan and in Europe where the prices are higher, I believe the equivalent price of a ton of coal in Japan from Australia is roughly $70 a ton; two or three times what a ton of coal would typically cost in some of the western locations. So, they've gone to higher efficiency more than we have.

Now, these are some of the potential coal sites that EPRI has taken a look at and said these are likely sites. You can argue about any of these; there are others that aren't on the list as likely sites yet.

Most of these are yellow dots and they don't show up at all on the handout, I'll add. The names do, but the dots seem not print very well in black and white.

But the green dots include some fluidized bed. In fact, some of these in Pennsylvania that use waste coal actually get something that looks like a renewable energy credit because they're cleaning up an environmental issue, this spent material that came from earlier coal mining.

There are a number on here that have been proposed as gasifications. The Stanton Station is the one I was talking about that is proposed as a gasification test with low sulfur, low rank western coals.

How do you clean a pulverized coal plant, what's done? Well, you pick the fuel, and the west makes it pretty easy because the fuels are low sulfur. You pick the burning technology; and these days all the burners are low NOx burners, and they're on the fourth generation now of low NOx burners. And they've done a lot to reduce the NOx by the fluid dynamics and the combustion dynamics in the boiler.

You do the same thing we do on our automobiles, you have catalytic converters these days on most new units being proposed who will have selective catalytic reduction for NOx. You use either a precipitator or a bag house. This happens to be a picture of a precipitator. They've gotten larger. The bag houses are very much like a vacuum cleaner bag on the old upright vacuums with the dust collected inside. And then shaken off periodically. But it's a very clean exit gas. Or electrostatic precipitator.

Or a scrubber. And the scrubbers are where you add an alkaline ground-up limestone to the acidic gas and react it to make gypsum, sulfur -- calcium sulfate. And if I tap the walls in most places you're tapping gypsum, because that's what's in wallboard.

I just would want to point out a couple of points here. The precipitators are very high efficiency, so are the bag houses. In fact, bag houses have been even higher in efficiency than shown here.

On flue gas to sulfurization there's a lot of controversy over what design is done for sulfur removal. And that is one of the biggest differences in the claims of gasification versus pulverized coal. I'll show you some numbers from our evaluations in a few minutes. But there is documentation that up to 99 percent sulfur removal is possible. When you're starting with a low sulfur coal, those are very low numbers.

Just to point out there's a lot of controversy over going to more efficient units. There are the terms sub-critical, meaning below the critical point of water, which is 3208 pounds per square inch. Below that point they're all sub-critical. They boil the water.

Above that point the steam is so compressed it doesn't boil anymore. It just stays as a fluid. So that's super-critical. Ultra super critical is just jargon term for very high temperature and pressure.

Super-critical steam is typically, as I say, above one pressure, but the highest temperature regime is not typically commercially bought in the U.S. Hundreds of super-critical boilers exist, including in California. Some of the Pittsburg units, the Moss Landing units, for instance, are super-critical boilers. They're fired with gas.

In the U.S. fuel prices made the choice less uniform. Even in China today they're beyond our steam conditions on the new units that they're ordering because the coal is more expensive.

The newest units have a efficiency over 40 percent and with lesser CO2 emissions commensurate with that efficiency versus a fleet average of about 32 percent in the U.S. today.

What the super-critical plants do is raise efficiency. The first three dots here are what has been built around the world from the sub-critical plants to the super-critical modest ultra super critical to the kinds of things that have been built in Japan and Germany and in Europe.

The projections are the kind of things we believe are possible; and, in fact, we with the Department of Energy and the energy industries of Ohio, have been looking at researching how to build these plants with the boiler manufacturers and the turbine manufacturers. The Europeans have a major program, as well, to develop these sorts of plants.

Right now there are about 310 gigawatts in the U.S. Most were built, as you saw in that earlier curve, some time ago. The new U.S. plants are typically sub-critical or modest super critical designs.

The uncertainty that is making people consider what they will have to do is really around the potential regulation of CO2. Main vendors are shown here. You'll notice both U.S. and European and Japanese names in the marketplace today.

So, what is fluidized bed combustion? That's where you circulate the material around; it occurs at a lower temperature which produces lower

NOx. You capture some of the sulfur in the bed. Many of the same conditions exist. This just shows you that there is one key difference in that they separate out in what's called a cyclone, to move the material around until it's completely combusted, and then the gases go through the heat recovery equipment.

Maximum size, right now about 300 megawatts, though larger have been proposed. These aren't the baseload plants typically. They are specifically aimed at certain fuels. There is about a 440 megawatt super-critical unit that's been ordered in Poland. None in the U.S. at this point. There are about 10 gigawatts of capacity installed in the U.S. And they work on all sorts of what are loosely termed opportunity fuels.

Pressurized fluidized bed combustion, where you feed it into basically a boiler in a bottle, has been developed in Japan. Right now we don't think commercial application is very likely because it's not as pressed in the offerings, and there are some developmental issues. Again, there are main boilers here, mostly European as well as some U.S.

On to gasification. And what we've been

typically referring to as integrated gasification combined cycle, literally the pieces are integrated, that's why it's called integrated gasification. And the last two letters there are combined cycle. Combined cycle is what we have a lot of in California. Two different thermal cycles. The steam and the gas turbine, itself, producing the power.

What you're doing here, you're taking air and distilling it, separating it in an air separation unit, that's the acronym. By the way, on the very back there's a whole bunch of acronyms if you need a glossary, on the very back page. And you probably do by the end of this presentation.

The gasifier, itself, takes the coal, makes a vitreous glassy looking slag that passes tests for leaching so that it can be used in materials. The sulfur is cleaned up. The degree of that cleanup is dependent on the emission standards of the specific plant. You'll see some data by others later that shows some interesting cleanup requirements on some of the earlier gasification plants. But you can clean it up very significantly.

Then you burn it, make power, and emit the CO_2 in this case. Or you can add one step called a shift reaction, and what that does is it takes carbon monoxide, water, makes hydrogen and CO_2.

You then remove that CO_2 and you can put it somewhere. It's a lot easier to do it with this, because the gas volume's much smaller and it is at much higher pressure.

You also make basically a purer stream of hydrogen. Now, this is one incarnation of polygeneration. You can take that hydrogen stream and you could put it into, for example, a refinery and back out some natural gas use at the same time.

Or, you can take these building blocks and put them together to make other things, liquid fuels; Fischer Tropsch liquids is a term you might hear later on. That's the super clean diesel. The Chinese are doing this with the South Africans today. The South Africans made a lot of this fuel when they were isolated by Apartheid. They have the largest single refinery of this sort in the world today.

But interesting statistic: 1 percent of

a 500 megawatt IGCC plant would be enough for 10,000 hydrogen-fueled vehicles. And it wouldn't cost all that much because you could sort of scalp off a little bit of hydrogen if you were trying to make it.

These are pictures of the different plants. You'll notice they sort of all look a little more like a refinery than they look like a conventional power plant. The one I showed you before in Indiana, the one that's down in Florida at the Polk Station. Two different designs. What's now the ConocoPhillips design; the General Electric design; and two different versions of Shell technology, one in Spain, one in Buggenum. This is the one that used the chicken litter that I was mentioning earlier.

Sulfur is normally removed from syngas at a high rate. You can go further than this, but the economics would tell you about 99.5 percent. NOx emissions are controlled in much the way they are in conventional combustion turbines, by firing and then selective catalytic reduction if need be.

Particulates, remove in-filters and water wash prior to it ever being burned. So it's quite clear, you look through the top of the stack at Polk you won't see anything. Heat waves, maybe, but that's it.

Current IGCC studies plan very low levels of SO2 and NOx. Mercury can be removed and has been removed commercially. Turns out that the Eastman folks have to because Kodak film which originally was, what, was Eastman Kodak, Tennessee Eastman, now it's just Eastman in Kentucky, they were making film. They had to remove mercury. It's too low to measure at the outlet of the device that's used for mercury capture. It's quite reliable.

Byproduct slag is vitreous. Water uses, we believe, and I'll show you some numbers from our studies, about 70 percent of conventional coal plant. But, again, you can use hybrid cooling or dry cooling to reduce that even more. In fact, EPRI is doing studies on those different designs with western and eastern coals with different water controls as part of our work that's highlighted in this journal.

CO2 under pressure takes less energy to remove, and that's why everybody is saying that is the capture capable sort of form of CO2. Takes a lot less energy. You've got less than 1 percent of the flue gas volume, so the equipment's less, the cost is less.

Right now there are these four plants that I showed you; roughly 250 to 300 megawatts in size. The main needs are capital cost reduction and availability improvement, in our opinion. The federal energy bill does contain incentives for these sorts of plants to be commercially deployed.

AEP, Energy Northwest and Cinergy have each announced plants at 600 megawatts roughly. And several others are in development, including co-production ammonia, synthetic natural gas and liquid fuels. I provided a presentation to the National Coal Council, a federal advisory committee, on what's going on in the alternate fuels area with some of these different liquids.

We believe there needs to be improvement for low ranked coals unless you use petroleum coke as a adder. We believe the worldwide market is really mostly based on petroleum residuals, the bottom of the barrel, either liquid or coke. That's where a lot is being used. There are, for instance, two multi-train 550 megawatt plants in Italy.

Feeding solids is harder than feeding

liquids, and that's one of the issues. The potential, of course, is there for southern California refinery placement of hydrogen as a co-product.

There are three teams of vendors and engineering firms, GE/Bechtel, ConocoPhillips, Fluor and I should have had -- sorry about that, Siemens on that team, Shell, Uhde and Black & Veatch are the three teams. Others in development, for instance, Southern Kellogg Brown and Root is the one being developed for western coal. And Future Energy is another firm looking at this development.

Probably the most controversial set of numbers you're going to see from me, they're all controversial, because every study has to be qualified. This one is qualified for low rank coals, done in 2002 to 2003. Since then the chemical process index of how much it costs to build something like this has risen roughly 15 percent.

So this was a snapshot in time, based on our studies, showing for Wyoming coals you've got two versions of gasification and a pulverized coal sub-critical. That's the headings. You've got a second version with a lignite, and this is a one version comparing that.

What you'll see is a capital cost that, for these designs and done in this way, is significantly greater for the gasification than the sub-critical, on these western coals. And that when you convert these to cost of electricity you can see that the gap is even more than what's typically talked of at 15, 20 percent.

This isn't the same for every technology. It's a specific study done a couple years ago. But you can see this is the gap we're talking about in the estimates.

By the way, I have to say, EPRI loves all the technologies for efficiency, for renewable, and for transmission, as well as all the generation technologies. My CEO said that last week at a seminar. We love them all. So, in one sense we're neutral; in another sense we're advocates of all the technologies. Just so I put it in proper perspective.

The current -- if you want to capture CO2, what can you do. Well, you can capture it. It has been done. Even on pulverized coal. But for pulverized coal the current technology is a certain type of a mean, a certain chemical compound, grabbing it in absorber, and stripping it out with energy. The problem is it takes a lot of energy.

Future improvements, there's a lot of work going on. The DOE, who will be talking to you later, has a lot of work in trying to develop improved solvents, lower energy use; novel processes, enzymes, mineralization, biomedic or imitating nature processes; ammonia scrubbing, we've been working on some of that. Novel equipment for contacting; improved designs.

All this says is there's a lot of work going on in this area to try and improve what's right now the big cost adder. There are alternatives, burn coal and oxygen; make CO_2. And then compress it and put it in the ground. You don't have to capture it after you've made it as almost pure CO_2. Or gasification, which is what we were talking about.

Again, one set of numbers with qualifications; these are not even U.S. numbers, these are Canadian numbers. But the coal deposits didn't really know where the borders were. And it turns out that bituminous coal is similar, not the same as, similar to -- pardon me. Those happen to be U.S. coals -- sub-bituminous coals are similar to U.S. sub-bituminous coals. Not quite the same. Lignites are a little different, but they are similar to U.S. lignites.

The point here is, based on this one set of studies, we could say that even with CO2 capture there could be less of a incentive to go to gasification in western applications. Now, these are being redone. We're part of the Canadian Clean Power Coalition study and working with our members in Canada on this evaluation. But this would say that if you did have to capture CO2, it might be cheaper in the lignite case to have a pulverized coal with capture on it.

Now these are very expensive power prices up here. There's a lot you can do in every one of these bars to work the numbers down.

The simplified version of how you catch it, is you put it into a large tower. You put amine-sorb in the top. You run the CO2-laden flue gas from the bottom. And you clean the gas. And then use a lot of thermal energy to so-called strip out the CO2, compress it. And that's how you get out CO2.

There are a lot of commercial processes. You'll notice some California companies, as some of the people that work on these, as well as some that aren't. They have been worked up to 300 metric tons a day, if you're talking about a large plant, it's a much larger scale.

Requires flue gas pretreatment. Before you ever put this into amine scrubber you're going to get out all the SO2 and all the NOx. Because otherwise you're going to have very expensive makeup requirements on these very expensive amines. You need a lot of steam, and that's a huge requirement for energy. It'll knock the efficiency back to about 1925 vintage boilers if you did this and did nothing else.

How do you get on -- my only other prop here is the fact that this is a rather large study we did a couple years ago on what you could do for phase construction of IGCC plants for CO2 capture. The effect of pre-investment. What could you do to pre-invest sort of the CO2-ready designs. What would it take.

And it's not as simple as we thought originally. It will take -- capturing CO2 from an IGCC plant will take less energy and equipment than a pulverized coal plant. But it's not just as simple as leaving some space.

The gasifiers and the air separation units would have to be bigger to match the requirements later on in the process. You need more moisture, and so the design might be chosen differently if you were saying I will take out CO2.

Pure hydrogen turbines that would be required for this haven't been run at full scale. The newest class of turbines have not been run commercially at large scale on syn-class-gas. There may be new blading if you're going to use another class of turbine. These are all issues that can be resolved.

New burners might be needed. You wouldn't use the same burners you would on natural gas. And our estimate from a 2003 Parsons study, again a company that you should know well in California, said that you might be able to spend $30 a kilowatt now and save roughly $50 a kilowatt later. The trouble is when's later and how do you then make that commercial cost justification.

I know some studies done by several universities out of California have said it never pays off. But, again, we've done some study work to understand that. We believe more work is needed in this area.

Just to point out, my last subject will be emissions. The U.S. has tripled its coal use in the last 30 years. Most people don't know that. We've certainly increased electric generation about a factor of two and a half.

At the same time we've produced less CO2; that's through fuel use; that's through scrubbing; and that's even with some of the unscrubbed units that are out there.

We've cut way down on particulate matter. NOx has gone up and back down. And it's an interesting comparison that the EPA did a couple years ago.

Another interesting slide. This is prospective emissions, not current emissions. Natural gas shows up on this as a tiny blip on the very far side, and it's all NOx basically, from what you can see from that distance. I'll show you a blow-up of the three left ones in just a second. IGCC, tiny blips; has a tiny blip for SO2 and particulate matter, but very low emissions.

The point that most people aren't aware

of is what a conventional pulverized coal, this happens to be on bituminous coal with higher sulfur, but even there the SO_2 is higher; the NO_x is almost the same; and particulate matter is pretty low, but it's not quite as low as gasification.

You'll notice that the new source performance standards make those numbers look very good, all three of them, all the clean coal technologies. The old PC's that are out there in operation, this is where coal gets its reputation and it's quite significant, looking at the two.

Now, let me expand the three on the left, and I point out these were developed under our Coal Fleet For Tomorrow program that I mentioned earlier, the absolute values are controversial. You will see some of that controversy in front of you later today.

The Powder River Basin, because it has lower sulfur in the coal, you saw the analysis earlier, if you do a very high percent removal you could be in a horserace here. It's going to be very interesting to see what happens.

A super-critical PC versus an IGCC, there are differences, but they're getting awfully close in the designs right now, in our opinion.

Solid waste comparison. These are for the four coals that we talked about earlier, Pittsburgh #8 and Appalachian coal, Illinois Basin coal, Wyoming and Texas lignite. As you'll see the western coals tend to have fewer sulfur byproducts, that's the red part, spent sorbent or could be gypsum. That's the red part of these curves. The other ones have higher sulfur. That's why they show up with more red. The ash or slag is a smaller portion.

There's one difference, of course, all the IGCC ones have that little yellow bar, and that's sulfur, which is a commercially used, quite clean byproduct -- or product, actually.

But this shows you the solid waste comparisons. The problem with lignite is not that it's horrible in the analysis; it's just you need a lot of it. You need twice as much to burn, and that's why you get more ash.

Water. Again, these are controversial numbers based on a specific design set and we are looking actively at multiple designs with multiple coals, including western coals, and including dry, hybrid and conventional cooling. But these are for conventional cooling, conventional numbers on one set of plants.

So the makeup water requirements in gallons per minute per megawatt is compared here. And it's roughly, our number is 70 percent of the amount in a pulverized coal plant.

Just one point. IGCC does, in most cases, require a slurrying water to slurry the coal in. And that's one of the water uses.

And I don't know if we have time for questions now. We may not, I'm not sure.

PRESIDING MEMBER GEESMAN: Mr. Larson.

EXECUTIVE DIRECTOR LARSON: Am I right, what you're saying is that if you compared the best coal technology that's currently available to natural gas, that you think that it's possible, in terms of emissions, that you can -- it can be equivalent? That you're close in terms of that technology.

And if that's so, then the big difference is in cost?

MR. DALTON: Basically correct. I would say close is the operative word there. What's good enough; what are the requirements. There still are sulfur emissions in this particular bar chart that I show here, with IGCC as an example compared to natural gas combined cycle.

Notice that the blue bar, the sulfur is much -- I mean, it's almost -- not quite infinitely, but it's much much higher than the amount of sulfur that you have occurring in natural gas. It's trace amounts in natural gas.

But it's very low. Now, there are techniques that can get it down just as clean, but those will add even more cost. So right now the issue is cost and that's been the big balancing act, is at what cost can you get the emissions to what level.

PRESIDING MEMBER GEESMAN: Thank you very much, Mr. Dalton, that was quite helpful.

MR. BIRKINSHAW: Our next speaker is Ronald Wolk. Mr. Wolk has more than 40 years experience in assessing, developing, commercializing of mass generation and fuel conversion technologies. And formed in 1994 the Wolk Integrated Technical Services, independent consulting firm.

Prior to that he served as Director of EPRI's advanced fossil power systems department. And he'll be giving us a brief history of clean coal gasification technology. Thank you.

MR. WOLK: I'd like to thank the Commissioners for inviting me today, and the people who put this together. I'd like to compliment them on an excellent program.

I wanted to spend a few minutes just reviewing the history of western coal and gasification. It's richer than people perhaps know about, and I thought it would be important to review for you.

California already consumes a fair amount of coal-based generation. The fractions of out-of-state plants owned by California utilities currently amount to about 4700 megawatts. And I'm sure there's lots of other coal-fired generation that moves into California based on perhaps a competitive advantage relative to other forms of generation. So, California already uses quite a bit of coal, in a sense; of course, it's imported.

As you've heard Stu discuss there are some general perceptions about the advantages of IGCC and the minuses. Generally it's perceived as a higher efficiency, lower polluting technology. Certainly less costly when high degrees of CO2 capture are required. And perhaps most significantly for the future, there's a very simple transition to go to hydrogen production, and to the production or co-production of other chemicals along with power.

The minuses are it's relatively high capital costs. It's low reliability. And perhaps most importantly, it's almost zero experience level within the utility industry. When utility management looks at IGCC plants, they don't see a power plant, they see a chemical plant. And that's not something within the realm of their experiences. And that's a real minus.

Now, as was pointed out by Stu, the pluses for IGCC are much greater on high-sulfur bituminous coals than they are on low ranked coals. The pluses come to almost a nil point in several cases. So the major advantages for IGCC are high Btu, high sulfur coals. And these diminish as rank diminishes.

This is an old slide; it was the best one I could find of the 100 megawatt IGCC plant that was built in Daggett, California at an IGCC -- I'm sorry -- at a Southern California Edison site.

The plant's fairly spread out. It was

designed deliberately that way so that we could have access to making revisions because it was a developmental project.

The operating period was 1984 to 1989. The gasification technology is now called the GE technology. The primary fuel for that plant was southern Utah coal, delivered by train, on the order of 1150 tons a day. We also tested, I think, at least four other coals, two eastern, Pittsburgh coal, Illinois coal, and a coal from Australia that the Japanese participants of the project specified.

The product gas was fueled by what I'll call an old-fashioned GE7E combined cycle. The information that was gathered from that project we used to design the Tampa Electric 250 megawatt plant that you saw a picture of. The thing that made that project possible was financial support from the Synthetic Fuels Corporation.

This is a picture of another Synthetic Fuels Corporation-funded project. It was built at a Dow Chemical plant in Plaquemine, Louisiana. The interesting part for this audience is that it used Power River Basin coal. It operated from 1987 to 1993. The name of the technology is now the E-gas technology. But it was 160 megawatts of net production.

The project refueled two existing natural gas-fired turbines. The normal fuel for the gas turbines was 80 percent syngas and 20 percent natural gas. And because of reliability issues and the need for that chemical complex to always have electricity the plant could instantly move from 20 percent natural gas to 100 percent natural gas if the syngas fuel was interrupted.

That information was used to design the second gasification plant operating in the U.S., the Wabash River Generating Station in Indiana. And, as I said, this was another Synthetic Fuel Corporation-supported project.

A third development during that same period from '87 to '91 was a 250- to 400-ton-per-day pilot plant that Shell built at Deer Park, Texas. It tested 18 different coals, including Powder River Basin coal, Texas lignite and southern Utah coal. And the information from that project was used to design the 250 megawatt Buggenum unit.

So, in all, the developmental programs have, at least for these three organizations, resulted in 250 megawatt projects. Those probably won't be the size of the commercial embodiments. I think those will be on the order of two-train plants of 500 megawatts, because the economics are much better.

These are pictures which you've seen before, and I won't dwell on them, other than to point out they all look about the same; they all look primarily like chemical plants as opposed to power plants.

The reliability issue is much discussed in terms of technology maturity. These are the availability history of those four plants in the pictures and the Cool Water Plant. Interestingly enough the red line at the top represents the Cool Water experience.

Now, you can see that each of these lines approach 80 percent. What the utility market seems to demand or tell developers that they want is 90 percent availability. Now, there are lots of ways to get from this kind of performance, which has been demonstrated approaching 80 to 90. The simplest way is making some additional investment of 10 to 15 percent, and put in a spare gasifier.

The Eastman project, which makes chemicals from coal, uses two gasifiers and over their almost 20-year history now, they've averaged better than 98 or perhaps 99 percent availability of syngas to feed their chemical systems.

So you can do it with money; you can do it with technology. If you had better refractories in the gasifiers you wouldn't have to shut down periodically to replace those refractories. That might be worth five points on availability.

Many of these projects suffer from what I'll call euphemistically fleet problems with the gas turbines. We didn't have that with the Cool Water project because that used an older model, well-proven technology.

But three of the other projects on this list used first-of-a-kind gas turbines; first-of-a-kind in the sense of the application on syngas for that model. So there might be another five points in gas turbine availability. So getting from 80 to 90 should not be a high technical risk for the industry.

Another technology that was mentioned briefly by Stu is an air-blown IGCC plant that will use Powder River Basin coal and is being built in Florida. And just think about that for a moment, of the stretch for delivery of competitive Powder River Basin coal from Wyoming to Florida.

The FutureGen project is one that's been organized by the Department of Energy. Its distinguishing characteristics are it'll make hydrogen and collect and sequester CO2 at a 275-megawatt scale. It has an estimated cost of a billion dollars. Its planned operation is from 2012 to 2015. I think approximately one-third of that cost is involved in the CO2 sequestration program.

The corporations on the bottom have formed a legal corporation now called, I think it's named the FutureGen Alliance, to pursue negotiations with DOE for this project.

Stu has already shown you the minor modification to go from a conventional IGCC plant to one that will coproduce hydrogen and also give you a very concentrated CO2 stream for capture. It involves the addition of the shift system.

DOE looks at this as a test bed for innovation to drive or to demonstrate in the field many of the technologies that they have under development currently or will have under development prior to 2012. And this particular embodiment shows integration with fuel cells to drive the efficiency up over 50 percent. It also shows CO_2 separation and CO_2 capture.

As was pointed out CO_2 capture in California is a commercial operation. I may have the capacity number wrong; it may not be 800, it might be 300. But its scrubbing technology has been in operation since 1978 at North American Chemical Company in Trona, California. And the CO_2 is used for carbonation of brines to produce soda ash.

So CO_2 capture in California with an MEA scrubbing system is really old hat. It's not the kind of technology you would use with an IGCC plant, but it's fairly close conceptually.

Okay, I wanted to spend a few minutes on, I guess, some facts and my opinions about what has changed recently. The big impact, I think, on the future of coal-fired generation in the country is the price of natural gas. And not for the obvious reason of reducing power costs.

I see it as really a paradigm shift. Most of the hydrogen in this country is made from methane. Most of the chemicals end up being made from methane. At current prices of methane I believe that syngas, hydrogen and those chemicals can be produced more cheaply from coal.

This means that the utility industry is now faced with a real challenge. If they just look at IGCC for power generation that's one view. If you look at it as a business where the objective is maximizing your profit, if you make syngas you have other opportunities to sell it perhaps at higher prices than you can get by burning it to make electricity.

And this really will or should demand a different kind of analysis for projects. It may mean that the conventional utility is not the best route to commercialization of IGCC technology. If they're not comfortable with chemical plants at the moment, that has to change, or else they will have to give up that sector to perhaps chemical or petroleum companies.

Second point. Coke, which is an excellent feedstock for gasification, is now exported from the Port of Los Angeles, I think it's the major coke export site on the west coast at low prices. It certainly could be gasified in refineries in the L.A. area to make lower cost electricity, that could be made from natural gas-fueled gas turbines at current prices.

There's been an L.A. coke gasification project under study, I think since 1975, and it never quite gets there economically.

So, the question, I think, is, is it the time for competitive coproduction of electricity, SNG chemicals, Fischer Tropsch liquids from coke, certainly, and coal now arrived. That's the question I think you should reflect on.

CO2 from one U.S. SNG coal gasification plant in North Dakota is piped 200 miles into Canada to use for enhanced oil recovery. In many southwestern U.S. locations we take sequestered CO2 from natural formations, put it in pipelines and move it to enhanced oil recovery sites. Now, the cost of doing that is fairly low. It costs about $10 a ton to deliver that CO2 to enhanced oil recovery sites from natural sequestered corporations.

We're looking at injecting CO2 from power plants into local saline aquifers; at the same time we're taking sequestered CO2 out of other resources. So that raises the question, will there be a market for coal-derived CO2 in the U.S. specifically for enhanced oil recovery to replace the natural CO2 that's being used now.

Despite the great publicity about how many new coal-fired plants are needed in the U.S., there are very few now under construction. Although many are planned in the near future. More than 100 are now under construction in China. And I kind of pulled that number out of the air, but I think it's right.

There are no IGCC plants now under construction in the U.S., other than perhaps a demonstration plant in Florida. There are no coal gasification for chemical production now under construction in the U.S.

Many such plants, more than ten that I know of, are under construction in China, which, to me, indicates that unless we get off our duff that we will lose the technology lead on IGCC to China.

Shell pointed out in a recent paper at the EPRI gasification conference that the cost to them to obtain what a relatively sophisticated gasification reactor is, and not typical of all, are really much cheaper in Asia than elsewhere in the world. Perhaps they cost only 60 percent as much.

More importantly, U.S. fabricators no longer have the capability to produce these reactors. Imports of gasification reactors from Asia could markedly decrease IGCC capital costs. I don't know if that's a politically acceptable solution, but worldwide procurement is really necessary to drive IGCC capital costs down.

And finally, I raise the question, and I'm sure it's one that you're considering, is it time to reconsider the use of solid fuels for power and chemical production to serve California's economic needs.

And with that I'd be happy to take any of your questions.

ASSOCIATE MEMBER BOYD: Question.

PRESIDING MEMBER GEESMAN: Commissioner Boyd.

ASSOCIATE MEMBER BOYD: Mr. Wolk, I'll let Mr. Dalton get away with asking him the one question I had for him. Unfortunately I was distracted for a moment.

But you brought the subject up again, and that's petroleum coke. And this is a question to you, but if Mr. Dalton wants to get in, also, that would be fine by me.

I've been interested in the use of petroleum coke for some good use within California ever since I've been -- well, actually before I even became a Commissioner.

And in repeated discussions down through the years with the refining industry about using their coke for, for instance, electricity generation; and particularly during the depths of our electricity crisis.

The suggestion has just been repeatedly spurned as totally uneconomic and we'd rather ship it away.

You raised good questions about that, and I'm just wondering if either of you is sensing any interest on the part of the refining industry in reconsidering that. There was a real appeal for that during the electricity crisis, to consider self generation. In fact, we almost begged the industry.

Only one -- I'm sorry, two refiners did come in and do cogen units, self gen, during that time. And they got so burned by the changing California regulatory processes that they had said to me at the time, it's really tough doing business with the state; we're leery, but we'll do it. And now they say we're never going to talk to you again.

So maybe they've talked to you. I'm just wondering if you're sensing any interest at all. To me the economics seems like it's turned around quite a bit.

MR. WOLK: I have no knowledge of any serious interest at the moment. That doesn't mean that there isn't any or there is. It's just that I have no knowledge of it.

But there's an extrapolation to what I said, and I'd like Stu to answer in a moment. But most of the hydrogen used in California refineries comes from methane. It seems to me a natural application to start building pet-coke or coal gasification plants in California to supply that hydrogen to those refineries.

MR. DALTON: If I might add, yes, there is some serious interest these days. You notice the supplier of the E-gas technology is Conoco/ Phillips, obviously an oil company. The Shell organization is another supplier of technology. Both have significant -- and the GE process also would be capable of using coke.

But the oil companies, themselves, I would personally hate to have to go through the process of trying to add a gasification process in the L.A. Basin today.

(Laughter.)

ASSOCIATE MEMBER BOYD: I knew you'd say that.

MR. DALTON: Forget the technology. I would hate to have to get that permit.

On the other hand, supplying into a pipeline could be anywhere. It could be even out of state, and done out of state. The point is you could supply the pipeline instead of with natural gas. You might have to transport the coke, gasify it and bring it back, in that sense.

But I think part of it has to be the rework at the bottom of the refinery; getting permission to bring in coal into that portion of the L.A. Basin; reworking the bottom to make this all operate. I think that might be a bigger barrier than the current economics.

And it's, in a very real sense you're looking at a billion-dollar investment for a new power plant run with gasification. And so that's a little bit more than just a remake at the bottom of the refinery.

So it could be done. There is more interest, there's a lot more interest in multiple products today. But, it's not necessarily the refiners.

ASSOCIATE MEMBER BOYD: Thank you.

PRESIDING MEMBER GEESMAN: Mr. Wolk, can I ask you who the principal vendors are for the gasification facilities in China you mentioned?

MR. WOLK: Stu just said the Japanese, but I'm not really -- I'm sorry?

MR. DALTON: Shell.

MR. WOLK: Oh, I'm sorry, I misheard the question. Shell has licensed ten of those units, coal gasification units for chemical production in China to phase out production units that depend on naphtha reforming.

PRESIDING MEMBER GEESMAN: Thank you.

MR. WOLK: And I'm sure GE has a number of units also under construction. I just don't know the number.

VICE CHAIRPERSON PFANNENSTIEL: Question.

PRESIDING MEMBER GEESMAN: Commissioner

Pfannenstiel.

VICE CHAIRPERSON PFANNENSTIEL: What is the size of the ones being built in China? I understand that one of the issues here is that nothing had really been tested at a larger scale than the relatively smaller ones.

MR. WOLK: I believe they're the same size as the unit that was built at Buggenum, on the order of 2000 tons a day of coal feed.

VICE CHAIRPERSON PFANNENSTIEL: What is that in megawatts?

MR. WOLK: That would be 250 megawatts.

VICE CHAIRPERSON PFANNENSTIEL: And that's sort of the largest that we've seen anywhere?

MR. WOLK: Shell will argue that they're capable of having single-train gasifiers that will supply a 400 megawatt gas turbine.

VICE CHAIRPERSON PFANNENSTIEL: Okay.

PRESIDING MEMBER GEESMAN: Mr. Wolk, thank you very much.

MR. WOLK: Thank you.

MR. BIRKINSHAW: Okay, we have one more presentation before lunch. And I think this is one that will get to some of the questions

Commissioner Pfannenstiel was asking this morning. We're going to be talking specifically about coal technology, how clean is clean, at what cost and when.

Our next presenter is Alex Farrell, Assistant Professor in the Energy and Resources Group at UC Berkeley. He has a degree in systems engineering from U.S. Naval Academy. And has most recently been working over the past decade on a number of energy and environmental policy issues.

With that I'll turn it over to you, Mr. Farrell.

MR. FARRELL: Commissioners, thank you very much for the invitation to come speak with you today. I'm happy to note that this work is supported by the Carnegie Mellon University Climate Decisionmaking Center.

The reason I point that out is I'm going to talk about a reasonable body of peer-reviewed research. A lot of it is conducted by my colleague at Berkeley, Margaret Taylor; and some of it by Ed Rubin, who is at Carnegie Mellon. And interestingly, both Margaret and I both were at Carnegie Mellon for awhile, which as you probably know, sits atop part of the Pittsburgh seam.

And it's interesting to see that the junior professors from the UC System are the two professors in the UC System actually who have got a fair amount of experience with coal. It's an interesting phenomenon.

I'm going to do a couple things. First, I want to talk about some pollutants and control technologies. And the most important thing that I want to talk about is what it takes to develop these technologies that are environmentally friendly. I will talk a little bit about the costs. And last, talk about innovation and policy.

I have three key points, and the first one I want to state very clearly. That given suitable policies, affordable coal-fired electricity can be compatible with environmental protection. I want to be clear that I do not mean to say that affordable, zero emission coal-fired electricity is what I have in mind. What I have in mind is coal-fired electricity that is affordable and fits within the framework of activities that meet environmental goals that we have.

Second, technological innovation and

adoption of environmental protection, or technologies that promote environmental protection requires public policy. It does not happen on its own. This is one of the main things that Margaret and others have been working on.

And the last observation, the last key point is public policies exist for all the pollutants we're going to talk about with one exception, and that, of course, being carbon dioxide.

Let me show you just one slide on solid waste. I'll also briefly mention one thing on water. Solid waste, or as sometimes called, coal combustion products, are a waste product, but they can often be marketed in Europe. More than 90 percent of CCPs are marketed today. In the U.S. about a third of the products are marketed.

Another theme that'll come up is there's a lot of interaction between the technologies that are at coal-fired power plants or other coal-processing facilities. And one of them shows up here, ammonia is used in a lot of these facilities. And ammonia, if it is not managed properly, can end up in the coal combustion products and make it either unsalable or just plain old difficult to handle. So this idea of interaction is going to come up a lot.

I think the bottomline is surface disposal of solid waste is somewhat expensive. It can be mitigated through sales, but I don't believe this is, especially in the mountain west, is a significant constraint.

One thing to point out on water, the idea of using saline groundwater was brought up. Of course, it's always possible to desalinize water if you're near an ocean which, I think, points to the larger idea that water may well be a constraint, but it could also be thought of as just a tradeoff with efficiency. You can get all he water you want given enough -- if you're willing to pay enough in terms of energy efficiency.

First to smoke and coarse particles. The reason we're interested in these particular pollutants is because of both health issues and visibility. How big a problem is it. I'm going to mention the source of this map. This Western Regional Air Partnership or WRAP, I'll mention this several times.

This is their map. And WRAP consists of

the States of New Mexico, Colorado, Wyoming, the Dakotas, all the way to the west coast. So all the states you see here less Texas and Oklahoma. It does include Alaska.

These are the regions in the WRAP area that are either nonattainment, moderate serious nonattainment areas; class I areas, so parks like the Grand Canyon here; or maintenance areas that are being watched for smoke and particulate, coarse particulate.

You can see it's not a particularly difficult problem except in southern California. More to the point, perhaps, is that coal-fired power is not a major contributor to this particular problem. It's mostly over here in miscellaneous, which turns out to be residential wood combustion, unpaved roads, paved roads, et cetera.

And the reason for this is while coal-fired power plants produce a lot of ash, more than 99 percent, in many cases more than 99.5 percent of these emissions are captured at the power plant.

I do want to point out again in this theme of interaction and important distinction between the technologies that are used. Very common is electrostatic precipitator. They work this way. There are plates, and you might be able to see, there rods that go in between the plates. This is a vertical view of this device. The rods are the discharge electrodes, the electrons move through the air from the discharge to the anode to the collection electrode which are the plates.

And what happens, as the particle-laden gas passes through this device, the particles are moved towards these collection electrodes. And, in particular, out of the way of the gas.

The fabric filters look like these, large devices that, as was said before, work more or less like vacuum cleaners.

The gas flows through these bags and it flows past the particles. And this, in fact, is -- although you may not think it's a big distinction, is, in fact, quite important. The electrostatic precipitator results in relatively poor contact between the gas and the particles. Whereas the fabric filters, because you go through several of the filters through the gas stream, there's repeated and continuous and close contact between the particles and the exhaust gas. And we'll see why this matters in a couple minutes.

Sulfur dioxide we've heard a bit about. Why do we care? Well, acidification is one of the main reasons. It has a role in global warming; I won't talk about that very much.

In the west it's mainly haze, secondary particle formation. But it also turns out that these very fine secondary particles are very important for health. How big a problem is it. This is aerosol light extinction of -- this is actually data, causes of haze assessment is part of the WRAP process -- at the Grand Canyon, average for five years, '97 to 2002.

And you can see that from the best days to the worst days it varies quite a bit. And, in fact, while sulfur is an important constituent down here at the bottom, and nitrate, let me just point out for our later discussions, is also an important constituent -- it's actually coarse particles and elemental carbon and organic carbon. These are going to be carbon compounds in the atmosphere that make up the bulk of the problem, as you move from the best days to the worst days. So a moderate problem.

What are the role of coal plants in

terms of SO_2. This is from a recent WRAP emission inventory, so electric utilities are down at the bottom in the brown. You can see that, in fact, from this perspective the SO_2 emissions from coal plants in the WRAP region are pretty significant. So for the moderate problem that sulfur dioxide presents in the WRAP region, coal plants are a reasonably sized contributor to that moderate problem.

Now, we begin to get into the technologies of control. What's the experience. This shows only for U.S. coal power plants. It's a little bit different than some of the figures you saw before. Generation in blue from 1970 through year 2002. And total SO_2 emissions en masse in the orange.

And you can see that the SO_2 emissions are declining and the electricity generation is increasing. And, in fact, the reduction in rate has been quite significant, the emission reductions have gone down on average 75 percent. And this 75 percent wraps up both some plants that have been cleaned up quite significantly and some that have been cleaned up very little, if at all.

How did this happen? Well, one of the

ways that it happened, as we've heard a little bit before, is through the replacement of high sulfur coals from the east and from Illinois, for instance, with coals from the west, especially Powder River Basin right here, which have very little sulfur.

This figure's from Denny Ellerman and Juan Pablo Montero's paper from 1998. And it shows for power plants burning PRB between 1985 and 1993 a few of them decreased. There's a few circles on here, and I can point to one there, and there's a couple others.

There's been a few that have had slight changes in the vicinity of the Powder River Basin. But these, the star and the cross signs here out in the midwest, all the way down into Florida, and down into the Gulf region, are either significant increases or new customers. Even some new customers out here in the Seattle area.

So fuel switching was quite an important phenomenon, at least in the early part of the previous slide, the decline of sulfur intensity in the electric power sector.

But another factor that's also important, is that most of this from emission reductions are due to lower emission rates at existing units. There has not been a replacement of older dirtier units. This is an issue that some people thought at the time of the passage of the Clean Air Act that the old units could be grandfathered because they would only be around for so long. I think we now know better. They're around forever because they're paid off and small amounts of maintenance can keep them going at a much cheaper rate than new facilities.

Just as an example of the technology that's really become dominant, the limestone scrubber. This is on a 150 megawatt unit in Denver, Cherokee Station. And this is just the formula for the reaction.

The reason I put up this reaction is to remind us that this is not the only way to scrub flue gas from a coal-fired power plant. And, in fact, 30 years ago there were many possibilities. But this is he one that's become dominant. It's not exactly the only one. But there's been a process of technological evolution by which this technology, in a horserace with others, has come out to be the winner.

Now, we begin some of the analysis of

how did this happen and why did it happen in the way that it did, again by Margaret Taylor of the Goldman School of Public Policy and others. This figure shows from 1972 through 1999 the year that the scrubbers went into service in terms of gigawatt electric power production at the units they were at.

And you can see that the U.S. is the early part of this curve, and also the largest part of this curve, with Japan coming on at a much lower level and Germany suddenly coming on here in the late '80s. And notice that there are these rather discontinuous features which are quite clear, features that are associated with firm emission control regulations.

This is probably one of the most important slides, this slide on induced innovation. What this shows is actually three types of data. First of all, it's performance data, so these dots are all performance of flue gas sulfurization units installed in the U.S. And they're plotted as yearly data given the cumulative capacity that had been installed to that date, so the dates are also shown; although the date is not the axis on the horizontal.

And in the vertical is the performance of the unit. So this is a 78 percent emission reduction, this is a 79.5 percent. And you can see out here these units are now performing at over 90 percent reduction.

So what we can see here is that over time a pretty clear and reasonably straight line suggesting that the more experience we have in constructing these devices, the better we can make the devices work.

At the same time, if we plot -- again, on the horizontal cumulative capacity in gigawatts electric, with the capital costs in dollars per kilowatt, in real dollars 1977, we've not only got these technologies to work better, we got them to be cheaper, as well. So, better, faster, cheaper if you will shows up in this particular environmental technology. But only here because of investment in R&D, as well as experience.

Because what's interesting about this data here is the plants, some of the FGD units down here are in this data. Not all of them, but some; and there are new ones, too.

A lot of this improvement is what's

called learning by doing. That is, we learn how better to operate some of the same units, as well as how to build units that operated better.

And this now brings, I think, to the most important of the themes I put up at the beginning, this question of induced innovation. Innovation is a costly and risky endeavor that firms normally undertake because they can be rewarded in the marketplace for taking the risk. They're rewarded either by higher market share; sometimes they invent new products and get the entire market share. Or sometimes simply higher revenues for the new or improved products.

The problem is that the environment is either a public good or an externality, depending what framework you have. And with the exception of a small number of green consumers who have usually a relatively limited impact on the market, the environmental performance of technologies is typically not part of the purchasing decisions of consumers.

So the mechanism by which firms are rewarded for taking the risk for innovation ain't there. Therefore, there's a reason for government to play a role.

There are a number of different ways in which government can play a role; patent protection is one; direct R&D expenditures are another; and demonstration projects also are important. However he work by Taylor, Rubin, Hounschell and others emphasizes that regulations that require a new technologies, almost to the point of technology forcing. And I'm not going to argue for or against it, just to note that we're getting close to that idea, really serve a vital function.

When you're doing a direct R&D, when you're doing demonstration projects that are government funded, the emphasis on cost control all the time may not be there as strongly as in commercial operations.

In addition, there's the opportunity for learning by doing. This can be on a firm specific basis, or it can be on an industry-wide basis, because often under the regulation industries will act together in ways that they might not otherwise want to or be allowed to work together without the case of regulation.

And finally, like I alluded to before, post-adoption innovation and learning by doing can also occur.

One other finding that's pretty clear is that uncertainty in the policies that would drive these effects weaken these effects very significantly. So firm regulation that are clear market signals as others have suggested, that the buyer wants clean electricity, define clean as you will, are quite important for a number of these different effects.

Let's now turn to NOx. We're interested in NOx for a couple of reasons. It actually contributes to acidification. It contributes to fine particles, health, haze, as well as ozone or smog. And in the mountain west, anyway, it's mainly fine particles and haze that are the problem.

Here you can see that in 2002 coal-fired power plants are slightly under a fifth of the problem, about 19, 20 percent of total emissions. This is mitigated somewhat by the fact that where the emissions occur matters a little bit more. What the emissions are like. These are vertically entrained hot emissions usually occurring in rural areas. They do not have the same impact on smog as these transportation emissions which are at the ground level near where people live in urban areas.

But ignoring those sorts of differences there's clearly more of a problem here with coal plants than there was, say, for PM.

We have a similar good story to tell with the experience, there's a 50 percent emissions rate reduction since 1970. You can see emissions have gone up and come down. I think you've seen that before. And, again, these reductions here can be -- we can point to specific parts of air pollution regulations that have led to those sorts of changes.

The technologies here are somewhat more complicated. There is combustion control that limit the production of NOx. Those are a few of the names for them. And then there's post-combustion control that remove the NOx from the flue gas. There are really two, basically, that are at work. They basically are doing the same thing. They're trying to drive this NOx in what's called chemical reduction from NOx to elemental nitrogen and the oxygen usually ends up in water. You can use a catalyst or not use a catalyst.

Again, these are quite substantial

capital investments. This is the Merrimack Station in New Hampshire. Here's the boiler; here's the electrostatic precipitator; and here's the SCR unit that's been tacked onto it.

Ed Rubin has done, again with some of his colleagues at Carnegie Mellon and with Margaret, analysis of the same variety for SCR installations. And they end up with a somewhat similar tale. That is we can see a different pattern in terms of which countries are going first. Here it's Japan that goes first, and Germany that really takes the lead in terms of installing capacity. You can see this big rise in the mid '80s, and then especially towards the latter part of the '80s.

And they end up with the same sort of effect as the figure's presented a little bit differently, but the idea's the same. This is worldwide SCR capacity installed at coal-fired power plants on the horizontal axis. Note that it's a log scale. And it's SCR capital costs, again note that it's a log scale. From 100 percent, picking 1983 costs at 100 percent. That's when the installations at Japan started to happen in a significant number. And you can see a significant decline through 1995, down say 40 percent reduction or so.

I do want to note, though, that this is a log scale. This is not something that happens slowly. It takes awhile to learn how to do this. But we've got at least two cases where that's happened.

Let's go to mercury; mercury's a different story. For the most part we're interested in mercury because of health effects; effects particularly on young children. It is a pretty significant problem. It's a hemispheric bio-accumulating pollutant.

What I mean by that is that there is what's called a global pool of mercury because it's a volatile at standard temperatures and pressures. It tends to migrate sometimes long distances. It tends to migrate towards the poles because the tropical regions are warmer, there's more evaporation than condensation; then the poles, there's more condensation than evaporation.

And, in fact, a significant fraction of the, in fact more mercury that is deposited in the United States comes from outside China than inside. But it is an issue that is also significant in scale. Global mercury emissions just from coal power plants are about half of all the anthropogenic emissions globally, and about a little bit more than three-quarters the size of natural flows. This is a pretty big disturbance under the ecosystem.

The U.S. it's a little bit different. Only about 40 percent of emissions are from coal power plants. But, they are the only major source without controls.

What's interesting is about 75 tons of mercury enters the coal power plants every year in this country as a contaminant in the coal, but only 48 tons leave. The remaining 27 tons actually goes out with the ash in the scrubber sludge. And, in fact, there are other toxics as well that don't get the attention that mercury does. They all go out with the ash in the scrubber sludge, as well.

So the challenge is this remaining 48 tons of elemental mercury that leaves the coal plant as an extremely dilute gas. And being extremely dilute, it's very difficult for control strategies whether you want to oxidize it or capture it in some way to work, because you have to process the gas many times to do that. And unfortunately, elements of mercury is not very reactive.

So the main strategies are first to reduce the mercury in the incoming coal. To oxidize the elemental mercury; the little o means elemental. And capture the mercuric compounds, here mercuric chloride which turn out to be much more easy to capture than mercury, itself. And also to collect on particle surfaces.

And you may remember, as I pointed out this sort of funny distinction between different types of particle control technologies, whether they're in contact with the exhaust gas a lot or not. Turns out that this is an important feature for how much control you can get from the existing technologies.

So, first, from these strategies of specific management approaches, first monitor and avoid high mercury coal production. It turns out that if we can avoid, say, in thick coal seams, mining and utilizing maybe the top one or two feet and the bottom one or two feet of that coal seam, those have much more mercury in them than the middle of the seam. Or maybe treat them differently; send them to perhaps a unit that have mercury controls, and that's what you might call rationalizing coal shipments.

And so this is actually, it's possible with a little bit of smarts and not a whole lot of money, to reduce the amount of coal that's going into these units, or at least get them to units where they're not going to do as much harm.

The second is improved particulate matter controls. And the basic strategy is to add a fabric filter stage to the ESPs. And it's being done fairly significantly. Here's why. This is an information collection request by EPA, a study that was done several years ag, on jus how much mercury was being collected as it was often called a co-benefit to the collection of the particles.

And notice that the fabric filters for both bituminous and sub-bituminous coals are much more effective than the electrostatic precipitators. Largely because the way the particles, once they're collected, and the gas interact, as I described earlier.

And so one of the things that's happening is some of the modules in the ESPs are being replaced with little fabric filter modules to do that.

This is even more dramatic. It's possible to think about how to design and operate SO2 scrubbers and other air pollution control technologies in order to oxidize the elemental mercury and then capture it.

So this is for a plant -- doesn't say where this plant is, and I forget where it is off the top of my head, but this is a -- it is Mt. Storm, that's right. It does say Mt. Storm. And so this is in the eastern part of the country.

This gives element of mercury concentration, I didn't put the units up here, it's micrograms per thousand standard cubic feet per minute, I believe. In the red or the purple is the oxidized easy to capture; in the bluish color is the difficult to capture elemental versions. And this is measured at 3 points in the gas train for two conditions, the SCR on bypass and the SCR online.

So coming out of the boiler we've got concentrations over 20 mcg/10 cfm, most of which is the hard capture elemental mercury. When it gets to the FGD, that is it's gone past the SCR, this is reduced somewhat. And notice that there is oxidation that's occurring in the gas stream, in the flue gas, even after it leaves the boiler. But the SCR does this even to a greater extent, so that almost all of the mercury that comes out of the SCR is, in fact, oxidized.

Now this can be accelerated, and I believe in this particular case it is accelerated, by the addition of oxidants into the gas stream. But the result is that when you get to the SCR, and now you're passing the gas stream through a mist, an alkaline mist, almost all of the oxidized mercury can be captured, and now we've reduced by greater than 90 percent the emissions of mercury from this particular unit with very little extra cost and very little extra effort, a pretty significant way to go.

The last strategy is to add a sorbent. So now instead of relying on the existing pathways for collection of mercury or possibility of allowing the mercury or mercury compounds to collect on the surface of ash particles, we actually insert, inject particles, in this case activated carbon, interestingly most of the activated carbon in the U.S. is in fact the processed lignite, so we're injecting unburned coal into the exhaust stream.

And you can see, and sometimes you'll add oxidizers, you can see that the mercury removal rates can rise pretty high. They vary a little bit with coal types. And the upper figure here is for electrostatic precipitator. And you can see that it takes a fair amount of activated carbon injection, say, you know, 10 to maybe 15 pounds per million cubic feet in order to get to 80 percent collection efficiency. You notice the change in scale here. With the fabric filter you need much less of the expensive sorbent injection in order to get up to this 80 percent level. Maybe only 2, maybe only 7 or 8 pounds per million cubic feet.

So those are the strategies that are employed. We are not yet very far down the road on that. I'll talk about policy in a minute.

Carbon dioxide. Why do we care about it? Well, climate change is the obvious answer. Globally electric power plants emit more than a quarter of all anthropogenic emissions. In the U.S. you can see that coal-fired power plants are, in fact, the largest single source of emissions.

And unfortunately, I cannot show you a

very nice story associated with the control of CO_2 because we just don't have any experience. And to make matters worse, CO_2 is not a contaminant like sulfur or mercury, and it's not an accidental byproduct that we could do without or screen out like nitrogen oxides, it's, in fact, a desired product of carbon combustion. So it is quite a difficult challenge.

There are, I would say, three possible strategies or technologies. One is fuel switching. I won't talk much about fuel switching because I really am here to talk mainly about coal technologies, and fuel switching is irrelevant if you want to talk about coal technologies.

Biomass co-firing is like fuel switching, and I want to mention it. Unfortunately, the Commissioner who asked the question about biomass is not here. Hopefully he'll get to see some of the handouts.

And finally the thing that's been discussed a lot, carbon capture and sequestration.

Let's talk about biomass co-firing for a minute. This would be the addition of fibrous biomass material to the fuel stream at an existing coal plant with no small or major modifications.

Numerous demonstrations have shown this is technically feasible. And I would also argue that this is a nontrivial resource base. This paper's by Allan Robinson, Jamie Rhodes and David Keith.

For each state here is shown in the black a bar that gives 20 percent of coal combustion. So this is 20 percent of the coal combustion, for instance, in Utah. Utah is very dry, as the desert southwest states all are, and so there's not very much wood residue or wood or agricultural residue.

But you don't have to go very far away, to Idaho, even to Montana, even to Wyoming to find reasonable amounts of biomass that could possibly be used in this way at what are actually pretty reasonable costs.

And what's important is this would be the use of biomass in a large number of very large electricity generators that currently use coal. And the costs are moderate. This is the cost for electricity in cents per kilowatt hours as a function of the price of biomass. The price of biomass is quite important.

So, for two things. One is for the overall plant, and so we're assuming that the cost of electricity at an existing coal plant is about 1.6 cents. You can see that the price rises fairly slowly for what's called separate feed. You'd have to actually build a fuel feeding system just for the biomass. But if you have coal feeding, and one of the questions is how much biomass can you add to the coal and still keep the fuel feed system, which is designed for coal, not for fibrous biomass, how much can you add.

Well, if you can add very much at all, there is the possibility of really a very relatively small increase in the price, even at a relatively high cost for biomass.

So this is certainly a possibility. We've talked about or heard about CCS technologies. I won't say very much about this except to point out this is flue gas separation is the one that's quite different from the others. And a couple people have mentioned that these tend to be difficult to deal with.

The reason is that the carbon dioxide is a relatively dilute part of the gas that you're trying to process. And the reason is -- the other two processes I'll mention in a minute -- have the property that they take the nitrogen out of the picture.

This is AES' Shady Point facility. It's a fluidized bed plant, 320 megawatts. The air in here, the gaseous part of this system is air, which is 80 percent nitrogen, and a little bit less than 20 percent oxygen. And so what you're doing when you're processing coal or other fuels for this sort of system, including pulverized coal plant, you're processing a great deal of nitrogen. And it's separating the CO2 from the nitrogen, as well as heating up and cooling down the nitrogen, that turns out to be problematic. I think enough has been said about that.

This is a way to think about the three processes, flue gas separation is the one that's quite ready to go. It's in use, as we've said. Oxyfuel combustion, here what you're doing is you're taking the nitrogen out ahead of time, out of the air by cryogenic production of oxygen. Then your exhaust gas are two things that are easily separable, water vapor and carbon dioxide. But there's a big power efficiency it would take to do that.

And the last one, this is where IGCC fits in, is you can call precombustion capture.

This can be readily integrated with IGCC. And I should say either of these, this one is integrated or can be integrated with pulverized coal, it's likely that oxyfuel combustion could be retrofitted on a pulverized coal plant, although no one's, to my knowledge, has built a pilot plant even of that size.

But this is the one, this is essentially between this technology and these two that distinguishes between whether it be an IGCC or a pulverized coal plant.

Finally, you'll hear more discussion of this. You've already heard it mentioned. This is an existence proof. All of this can be put into practice and is. This is the synfuels facility down in Beulah, North Dakota. Here coal is produced, is turned into electricity. And the resulting carbon dioxide is put into this pipeline, piped across an international border, money goes the other way, to the Weyburn oil field where it is injected for enhanced oil recovery.

So, not only is this possible, it's done on a commercial scale. And remember, this is a government-funded demonstration project. I can't say it's actually commercialized, per se, but it is done on commercial scale in this country.

Let me turn to costs, everyone's favorite question. I first want to talk about allowance prices. This is one way to understand what costs are like. And I want to point out that costs are hard to predict.

Back in the early '90s people were predicting prices all through this range and higher. Not very many people got it right. Certainly this decline in prices down to $67 is that low point, was not really expected by anyone. But we can explain it nowadays.

Nonetheless, I want to point out that prices have been relatively low until the last six months or so, and now they run, well, in current dollars, around 850 bucks. Whether this price stays where it is, or whether it goes up or down, if I knew the answer to that question I would be in New York on Wall Street, not here.

But the point is, and these are nitrogen prices, nitrogen dioxide, these markets handle these swings in prices quite well. None of these firms have gone out of business; they've all been managing. And, in fact, this one is particularly interesting. Here I'm plotting both future vintages and current vintages in the solid line. They are treated differently in this particular regulatory program.

You can see that here in '99 it was clear there was a near-term shortage because of this price spike. But the rest of the market did not react in a panicked way. And, in fact, despite this price spike, which was quite expensive for several companies, the regulators did not abandon the marketplace. They let it work. And, in fact, allowance prices for several years were quite low until new regulations began to appear and people began to plan for those.

and, again, you can see there's this distinction between the prices for allowances that are relevant for long-term planning, and the prices for allowances that are relevant to the capital stock you have on hand.

So, I think the take-away message from these two is that it's hard to predict what these prices are like. And the implicit message is regulating air pollution nowadays is done through markets. Almost entirely, many of the new programs are done through markets.

This is another way to understand costs.

Here are some projections. And you can have various opinions about these projections. So, Energy Information Agency uses a relatively inflexible model called national energy modeling systems, NEMS.

In 2001 it projected what would happen for the Jeffords-Lieberman Bill, which would have had very significant reductions in all four pollutants, including carbon dioxide, in 2020. In their reference the average cost of electricity goes from $61 a megawatt hour up to $81 per megawatt hour.

But interestingly, the advanced technology, which is frankly fairly limited, so for instance, the biomass that I showed you before, none of that shows up in this model, really limits that increase quite significantly to only $67 per megawatt.

Many people think this is a high estimate. The Tellus Institute has recently come out with an estimate for California, Oregon and Washington, for greenhouse gas emission reductions of a pretty significant size, not quite that size, in 2020. And they find less than a 1 percent rise in electricity prices. Mainly because they look at a lot of efficiency improvements that were not in this particular model.

Now, coming back to this Western Regional Air Partnership, WRAP has recently estimated the cost of NOx control. They actually have a very complicated set of scenarios. I don't want to say that either of these two scenarios are particularly important, other than they are scenarios in which there are very large mass NOx reductions.

And you can see that the forecast for prices actually varies quite a lot. And so the impact for these particular regulations might be between a few tenths of a dollar per megawatt hour to perhaps a few dollars per megawatt hour. It's hard to make a distinct translation.

What about the importance of induced innovation. Well, the same crowd that was looking backwards at SOx and NOx has also looked forward in a modeling framework. This is Riahi, Rubin and others. And they are forecasting the carbon reduction cost. So this is a slightly different number than you've seen before. This is in dollars per ton carbon not emitted to the atmosphere by the electric power sector in two different scenarios, both for coal-based generation and gas-based generation.

Notice that they have, again, this very large cumulative installed capacity. But these slopes, even though it's a log/log curve, are pretty steep. And so it looks like, and they've done a few other studies like this, that the story that has been evident so far, that is technological innovation and technology, learning by doing, may have an important role here in forecasting what the price increase due to control of CO2 might be.

Here's the conundrum. This is Howard Herzog's, to prove I'm not wedded completely to Pittsburgh, Howard's at MIT, here's Howard's estimate of the cost of generation for three types of units, natural gas, and integrated gasification combined cycle, and a PC unit.

And I just want to illustrate, what's been mentioned a few times, graphically, that today, without the need for any advantages that IGCC unit might offer in terms of being ready for carbon sequestration or any other advantages, then this difference is significant enough so that this is the chosen technology. Especially if you think that gas prices in the future were going to be higher.

But if you're confident that CO2 with capture may be an option, well, your calculus changes. Nothing that hasn't been said before, just I want to graphically illustrate with one person's estimate of how big that difference is.

Lastly, since we're just at about noon, let me just skip through most of this section. Integrating these technologies is very challenging. It used to be coal-fired power plants 40 or 50 years ago were large boilers, for the most part. But since about the mid '70s the electric utility industry has actually become the proud owner of a large set of chemistry experiments, or chemical operations, where they are doing a great deal of sophisticated work trying to manage the content of their flue gases.

And so these processes interact. Sometimes they interact to produce plugging because some of your ammonia gets involved with some of the sulfur dioxide. Sometimes some of your constituents that you add to the flue gas in order to control one problem end up damaging a different part of the problem.

It was mentioned adequate space is often an issue. That's not the most important issue necessarily. And importantly, sequential regulations make this especially challenging. It is very difficult to add on to facilities.

And I'm going to skip here through a couple of -- an example for the General Gavin Plant, just show you the Gavin Plant. It's a 2600 megawatt PC unit. These are the boilers right here. I want to point out just a couple things very briefly.

First, this is the old stack. It didn't fit anymore when they had to put the scrubbers in, so they had to build new stacks, but they couldn't take it down safely, either.

The other thing is that the SCR units are here. The only place that they fit was on top of the units. They really couldn't find another place to put them. And so it turns out to be a very challenging thing to do.

This is the scale, by the way, of what you get for about 2.6 gigawatts of coal-fired power nowadays.

Turn to my last theme, innovation, or last part of the outline, innovation and policy.

I want to reiterate the fact that environmental technologies require policy drivers because there is no market for the environment with very limited exception.

There are a number of policies that are in place that are now, or have in the past, or will be in the future, influencing the technologies that we'll see for the pollutants that we care about. One is new source review. That has had a big effect in the past. As we saw earlier, there's a proposal for a more restrictive new source review.

You may hear of the Clean Air Interstate Rule. The important thing here it would reduce both sulfur and NOx quite significantly, but it only applies in the east. The indirect effect on California and the mountain west would be that to meet these requirements new technologies and experience with technologies will be developed.

The two things that really are influencing possible coal-fired power plants that would power California is the Clean Air Mercury Rule, which there was a new source performance standard.

But most importantly, a cap-and-trade

rule, which is a 70 percent reduction, about, by about 2018. Notice it's a cap-and-trade program. I'll come back to that in a minute.

The other one is a regional haze rule, or best available retrofit technology, not BART you ride in, but BART that helps clean up the air. This will really be what determines the sulfur and the NOx control requirements in the west in the coming couple of decades.

And what's happening right now is the western states are currently developing their state implementation plans to meet both of these rules through the WRAP process. And this includes California.

So then the question that I think is in front of the Commission, one of the questions, is there a role for California policy. Running through the pollutants very quickly I think in PM10 there's little to do. In sulfur and NOx, California's already participating through the WRAP process. And, in addition, it is very likely that the WRAP process will be like all other air pollution, or most other air pollution regulatory policies in recent years, and it will create a market-based regulatory mechanism.

The problem is that it is very difficult, either practically or legally, for a single state or single entity to influence these market-based regulatory programs. Several attempts to do so have been shown. Probably they would have had little or no effect had they been implemented. But, oh, by the way, the courts threw out the attempts by states to do that.

Mercury, again there's a new federal rule that will determine this. It's very difficult to influence these market-based regulatory mechanisms. Really it seems to me this is the place where there may be a role for California policy.

I think, and this is certainly, you know, we're well into the opinion area at this point. Executive order 305 is clear, California must take action to avoid suffering the effects of climate change. That means that production processes, whether electricity or chemicals or otherwise, for consumption in California, are increased -- lead to increased CO2 emissions, then there may be a role to do something.

Stu showed this very large number of investments in new coal power plants starting, according to those figures, around 2010, 2012. There may be an opportunity to influence those. And really the empirical evidence from prior examples, is well, we need R&D, and well, we need demonstration projects. These do not go far enough.

The summary, to try and answer, in one slide, the questions that I was asked. How clean can clean coal be? Coal-fired power plants can meet solid waste and air quality goals.

At what cost? Well, there non-zero costs. There certainly are some costs to be paid. But I don't think it's going to break the bank. We've certainly seen much larger increases in price due to errors made by various people in various times. You can see the previous slides for a variety of opinions.

For these three pollutants, PM, SOx and NOx, these control technologies are available now. And I would argue they're largely going to be in place because of the ongoing regulatory processes.

Break-through technologies are under active development. Several CO2 control technologies are possible. Some are deployable at very moderate costs. Some require a significant amount of development.

I think there are two challenges. One challenge, which I've not really addressed, is while there are existing policy drivers for many of the conventional pollutants, some people, and I would include myself in this group here, in some ways, believe that these policy drivers are inadequate.

The regional haze and the mercury rules have a variety of criticisms leveled at them. For instance, the mercury rule is a 70 percent reduction in 13 years; whereas it was pretty clear that some technologies can produce at zero cost, or almost zero cost, an 80 or 90 percent or more reduction today. That doesn't seem to make sense to me. But that's not a technology issue.

The real issue, and I think this is not just my opinion, I think this is an opinion that's held pretty widely in the academic community, I can tell you that at the University of California, throughout the system, at LBL, the challenge is to develop a energy system that is compatible with climate protection.

And there are a number of specific questions, when thinking about this, that ought to be -- that when the Commission is thinking about this issue, ought to be front and center. Will current and imminent investments in new power plants be capture-ready designs. And I probably am being a little bit too flip by labeling these two as capture-ready and legacy, per se. But the question remains. Are we ready to do capture when the time comes, if it comes.

What government will provide the policy drivers needed to develop CO2 mitigation technologies. Because this leads into the next question, when will these technologies be cheap enough so they can be widely deployed.

And these questions all sort of wrap up. You can't answer one without knowing the answer to the others. They all need to be answered at the same time.

And in my view leadership is needed to begin to drive down CO2 control costs so that preventing climate change becomes affordable.

Thank you very much.

PRESIDING MEMBER GEESMAN: Commissioner Boyd.

ASSOCIATE MEMBER BOYD: Professor Farrell, thank you very much. That was extremely interesting, particularly to some of us members of the air quality fraternity. It was quite reminiscent.

And not only do you have a former state air director in myself sitting here, but you have two former USEPA air directors sitting in the audience in the persons of Dave Hawk and Phil Rosenberg, so hopefully they found it as interesting.

And also just to allay any concern you might have about biomass, while the Commissioner who asked the question is out of the room, the Commissioner who's chair of the state working group on biomass is sitting here. So I very much took into account what you had to say. And I'm looking at my friend from the western states hoping they absorbed it, as well. Because I think we need to integrate that into our discussions. And I see former chairman Keese in the back of the room. We need to talk about biomass in that context.

Lastly, I just want to say, as a long-time disciple of the induced innovation regulation is technology forcing fraternity that I still have a foot heavily in that circle. And I certainly agree we've evolved towards market mechanisms.

But I also, being quite a student of the human species, I'm very leery sometimes about rushing headlong into a pure market mechanism. So I leave it to some of you folks to help us make the transition truly into being able to rely solely on market mechanisms.

As a long-time air regulator I was open to the idea. I'm, hopefully, pretty open minded on that. As somebody who then entered the energy field, markets is a word that scares some of us these days.

So, in any event, I found your presentation quite interesting and those who -- well, I guess all of a sudden I do have to worry about mercury in this capacity, as worrying about where my power comes from. As an air director it was all those other states who burned all that coal that worried about some of those things.

So, some very interesting suggestions and observations. And I definitely will take them into account in preparing our policy recommendations. And frankly, I don't have any questions for you, so thank you.

PRESIDING MEMBER GEESMAN: I had one.

And that is whether you have had an opportunity to give much thought to what particular technology-inducing policies the State of California might be able to adopt that would affect carbon reduction from coal combustion.

MR. FARRELL: Well, the things that are being done today for demonstration projects are all quite helpful. But having a policy that did prefer, in a way that made economic -- had an economic meaning to developers, low carbon emissions, that would certainly be helpful.

These technologies are rather large and expensive and capital intensive. And so some of the other approaches that have been used before, whether it's design competitions or other things that try and bring people's thinking to the forefront might be hard to do, but it might nonetheless be an opportunity.

One way to do that would be perhaps to structure a power purchase agreement, or power purchase opportunity that looks very favorably for a small amount of power, say one or two units worth of power as close to zero emissions as possible, and see who came to the plate with what technology designs.

Even to the point of as happens in some fields, funding a little bit of the teams that are doing that, so that they can think a little bit more creatively about what we really wanted, to meet some of these challenges, and win this prize, which might be some amount of electricity sales in the future, how far could we push ourselves. So there are a few things like that.

PRESIDING MEMBER GEESMAN: Thank you very much.

Seeing no other questions I think we'll break for lunch. Why don't we come back at 1:15.

(Whereupon, at 12:13 p.m., the workshop
was adjourned, to reconvene at 1:15
p.m., this same day.)

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AFTERNOON SESSION

1:24 p.m.

PRESIDING MEMBER GEESMAN: Kelly, who's next?

MR. BIRKINSHAW: Well, our next speaker is Dr. Larry Myer. But before I introduce Dr. Myer, --

ASSOCIATE MEMBER BOYD: Kelly, you've got to get closer to your mike.

MR. BIRKINSHAW: Sorry. Thanks. Before I introduce Dr. Myer, though, those who would like to make comments at the end of the day if you could fill out one of these blue cards. There's a stack of them out on the table just outside the door here. And give them to Peggy at the end of the table here. Then we'll have a record of those that want to make comments or have questions. And we'll take those at the end of the day.

So, with that, I will introduce Dr. Myer. He's a Staff Scientist at the Lawrence Berkeley National Laboratory, the Earth Sciences Division. And is the Technical Lead for the Western Regional Carbon Sequestration Partnership. And has been leading research on carbon sequestration since 1999.

The partnership is evaluating carbon dioxide, capture, transport sequestration technologies for the region comprised of Arizona, California Nevada, Oregon, Washington, British Columbia and Alaska. He has a PhD in geological engineering from the University of California at Berkeley. Larry.

DR. MYER: Commissioners, thank you very much for the opportunity to talk about geologic storage as an option for mitigation of carbon dioxide buildup in the atmosphere.

I want to talk about a number of topics. I have to make three key points. I'd like to make the following. And that is that geologic sequestration is, in fact, a near-term technologically viable option for mitigation of CO2 buildup in the atmosphere from power generation.

Secondly is that the cost of capture must be addressed as one of the most significant barriers to implementation of geologic storage.

And third is that experience from pilots is an essential step to gain confidence in this technology. And this is something that we need to do right away.

So, with those, I'll then sort of go into some of these, touch on a number of topics all somewhat related in one way or another to those key elements.

Where can CO_2 be stored, first of all. Then after we address sort of the broad question of where it can be stored, how do we know how much we're going to be able to store. Is geologic storage safe and secure. Why do we need to monitor, and we do. What are some issues related to cost, other than just capture. What if something goes wrong, what are our available mitigation strategies. Comment on the value of pilot studies and some comments on where we should go next.

So, as you've already heard this morning, geologic sequestration really encompasses a four-step process. It's not just the process of putting the CO_2 in the subsurface. But it encompasses both capture, compression, pipeline transport, and then underground injection.

So, first of all you think of a pure stream of CO_2 captured from a flue gas or other process stream, as we've heard about this morning. And then compressed to about 100 bars. So there's an energy penalty in compression of the CO_2. Then transported to the site via pipeline most likely. And then injected deep underground into geologic formations, oil and gas reservoirs or saline formations. And stored safely for thousands of years.

The first point to be made is that as a technology it is already underway. So, Alex showed an example of an EOR project in Weyburn, Canada, where CO_2, anthropogenic CO_2 is transported from the U.S.

There are two notable international projects in which sequestration is being carried on commercially. And I should say sequestration for the purposes of sequestration, as opposed to enhanced oil recovery.

One is the Statoil project, which actually predated both Weyburn and was the first commercial project in the world, injecting a million tons of carbon dioxide per year in the North Sea. That's the graphic over on the right side. And then British Petroleum is injecting almost a million tons per year at a new project in Algeria.

So, the point here is that the

technology for injection of CO_2 into the subsurface for purposes of sequestration is certainly available. The fact that we can do it at one or two places in the world is not sufficient. We need to look locally, regionally, to see what the opportunities and options are.

This graphic is to talk to the general topic of geologic storage. It tries to relate some important aspects of geologic storage in that it shows a number of layers in the earth. And these layers are representative of layers found in sedimentary basins primarily.

There's some discussion of storing CO_2 in other sorts of geologic formations other than sedimentary basins. But clearly sedimentary basins represents the first opportunities for storage of carbon dioxide in the subsurface.

And one point that I want to leave you with is a mental picture of geologic storage in sedimentary basins as not a separate set of options, oil and gas reservoirs and coal formations. But really you can think of oil and gas reservoirs and coal formations as localized parts of sedimentary basins and saline formations where there happen to have accumulated things other than salt water.

So when we talk about sequestering of carbon dioxide in the subsurface our first option is sedimentary basins where the sediments, porous sediments at depth are saturated with salt water. And there are portions of those sedimentary basins which sometimes have other things in them, like oil and gas, which we can use economically.

But those reservoirs are just portions of it and we can think of them as just the beginning points for moving out into the larger targets of the saline formations.

Moving another piece of information relevant to -- very relevant to the geologic storage option is thinking about the physics of what actually would keep the CO2 in place once you put it into the subsurface. And this cartoon is meant to illustrate those storage mechanisms in part.

We usually think of the storage physical processes as one being the physical or hydrodynamic trapping, which is actually what is illustrated by the cartoon, in which you have a roofrock which is a low permeability sediment. And it is structured in such a way that it actually, as you see, is an overturned bowl, and actually could, beneath that bowl collect, if you will, buoyant fluids such as CO_2, or, in fact, oil and gas. And then acts as a trap. So it's called a hydrodynamic trap.

We have the physical process of dissolution, phase trapping, mineralization. Dissolution means basically dissolving the CO_2 in the water. Phase trapping means that when you put CO_2 into the subsurface, because it is a nonwetting fluid, portions of it, when the salt water begins to move and mix with the plume, actually gets trapped in place. Mineralization refers to the fact that CO_2 is reactive and you form minerals in the subsurface and it is probably the most secure way of storing the CO_2.

And surface absorption refers to the fact that in such things as coal, CO_2 sorbs to the surface and is stuck there permanently.

So next I want to sort of walk through these things that everyone hears about all the time. Enhanced oil recovery, putting it into gas reservoirs and coal, and just a very short sort of few thoughts about these options.

So, we know that CO_2 sequestration with enhanced oil recovery is an economic now in the sense that CO_2 is used for enhanced oil recovery. Now, one thing to note, and the graphic shows the cartoon depiction of how this process occurs.

You have wells, some of which on the right are the production wells. Other wells on the left, the injection wells. So you literally pump the CO_2 into the subsurface.

It is usually done with water to push the CO_2. The CO_2, if it is put in at the proper pressure, will dissolve into the oil. It will reduce the viscosity of the oil and make it swell, and more easily move to the production wells.

It's worth commenting that if we do CO_2 sequestration as a priority as part of enhanced oil recovery, we need to optimize enhanced oil recovery for CO_2 storage. Doing enhanced oil recovery, in and of itself, is not necessarily doing CO_2 sequestration.

In enhanced oil recovery the option, what you want to achieve is a minimization of the amount of CO_2 which is produced back in the producing well. If you're trying to store the CO_2 you want to optimize that process, to keep as much CO_2 in the subsurface as possible.

Some of the additional research topics relevant to California in this regard are the need to look at the less favorable EOR targets. Enhanced oil recovery with CO_2 normally looks to light oils as the favorable targets. There's a lot of heavy oil in California. That's a potential research area.

Methane production can also be increased with CO_2 from coal. We heard this morning about the constituents in coal. And very often the carbon and hydrogen is combined as methane, which is absorbed onto the surface of the coal. If you put CO_2 into the coal, it will actually displace the methane and stick to the coal surfaces.

So, and here we have a graphic on the right which, once again, shows the usual way of working in the subsurface where you inject CO_2 in one set of wells and you push it into the formation and produce from another set of wells.

The advantage here with regard to sequestration is that you, once again, are absorbing the CO_2 to the surface of the coal making it a very secure type of sequestration.

Sequestration with enhanced gas recovery has potential. And this in particularly a point of reference in California where we have significant gas reservoirs in northern California.

It is, however, a technology that has not been previously demonstrated. Clearly, you can put carbon dioxide into oil reservoirs and enhance recovery. There's always been a fear that if you put carbon dioxide into a methane reservoir it will mix with the methane and contaminate the produced methane.

There have been a number of studies. The graphic on the left is an indication of one which implies that, in fact, we should be able to do this without a great deal of mixing. It turns out that the properties of carbon dioxide, being somewhat denser than methane, and less viscous, are actually very good for displacing of methane in gas reservoirs.

I wanted to mention one other thing with regard to putting carbon dioxide into gas reservoirs. I mentioned this problem of trapping the CO2 in geologic formations. The reason that we rely on geologic formations to trap the CO2 is that in most instances the carbon dioxide is less dense than the fluids into which you're putting it. It's less dense than water, it's less dense than oil. And so it will tend to rise by buoyancy. You need to have a physical structure in place to trap the CO2.

In the case of the gas reservoir, the CO2 is actually more dense than the methane. So you have a more secure type of storage in gas reservoirs than you would in situations where it is rising through salt water or oil.

So that's a bit of a primer about the options and what we can do with the carbon dioxide in the very near term.

Let's look at where we can put it. The graphic on the right is a graphic from the NatCarb site, which is a site established by the Department of Energy to assemble sequestration data for the U.S.

And what it shows is the distribution of point sources in red all over the western United States, and the distribution of saline formations in blue. And thinking back to what I said in the original comments I was making about saline formations I didn't show oil and gas reservoirs and coal here because they're sort of subsets of this. So the important information here is to look at the broad distribution of saline formations running up from Texas and through Wyoming and Montana and Utah.

There are ample opportunities for sequestration in these states, as you well know. You saw pictures this morning of coal. And, of course, we know about the extensive oil and gas production.

Now, having said that potential geologic storage formations are broadly distributed, I think you can tell from the map they're not ubiquitous. And looking at the degree to which they are ubiquitous is an area that is the subject of research; and it's an ongoing research area in the regional partnerships. It's something that we need to do in order to match up all those various red points with potential sequestration sites.

On the left part of this is a somewhat more detailed look at the western states. And it derives from the work we've done as part of the west coast regional partnership. And, once again, the graphic shows the major point sources and the sedimentary basins that could be targets for those point sources. You can see that it's a little bit more detailed than what is on the NatCarb base.

And what we are doing, in fact, as part

of the partnership program is to get the data from all the various partnerships into the NatCarb base so we have an updated detailed version.

So I think the other point that I really wanted to make with the graphic on the left in this was that you can tell, for example, in Nevada that there are major point sources. And though we show some areas of green on the WestCarb map, it's also clear that not all sedimentary basins are equal, or equally well understood.

And in the west, in particular, when I talk about the potential for ubiquitous sites, we have a challenge to look in areas such as Nevada where there is very very little information about the nature of the subsurface sediments.

And when you look at places like Idaho you have the challenge of major salt layers being on top, and very little access to sedimentary basins.

Turning to capacity assessment, once you have evaluated sort of at a broad level the location of the sedimentary basins, you still have to evaluate how much may be available for storage of carbon dioxide. And here I've just honed in on California.

And the bottomline for California is that it has very large potential storage capacity. And the graphic on the left shows in the light green the location of the major sedimentary basins which have sufficient depth to accept carbon dioxide. They have, in the red are the natural gas fields, which I alluded to as potential for looking at enhanced gas recovery. Darker green are the oil fields which are in the southern part of the Central Valley in California.

There are many factors which affect the capacity calculations. And so I have a graphic there on the right which actually shows a range of numbers for the storage capacity in the saline formations.

It's worth pointing out that there is uncertainty in doing capacity estimates for geologic storage. It depends on your knowledge, your detailed knowledge of the geology, the degree of heterogeneity so that you can evaluate the extent to which the CO_2 reaches all of the available porosity in the rock. It depends on your knowledge of the amount that's going to be dissolved. Depends on your knowledge of the amount that could exist in separate phase in the subsurface.

Taking those things into account you can do things like we did to make an estimate of the total capacity. And just looking at the ten largest sedimentary basins in California you can see numbers such as 140 giga-tons to over 800 giga-tons of storage capacity. These are numbers which indicate hundreds of years of storage capacity for the current amount of CO_2 being produced by power plants.

A comment relevant to policy in this regard. If policy restructured in certain fashion you could envision that the storage capacity of California could be a significant resource for California, the potential subsurface storage capacity is so large.

Turning now to the issues of safety related to geologic storage. We have many lines of evidence to indicate that geologic storage is safe and secure. Probably first and foremost is the natural analogs. And particularly the oil and gas reservoirs.

And this harkens back to my comments about looking first at sedimentary basins. They are the -- sedimentary basins are where you find oil and gas reservoirs. Oil and gas reservoirs have contained buoyant fluids, principally methane, which as I said before is less dense than CO_2, for millions of years. These are excellent analogs to show the long-term storage security of sedimentary formations.

There are also CO_2, natural CO_2 formations, that is natural CO_2 reservoirs which have contained basically CO_2 in the subsurface, and that held it in place for geologic time.

In the more near term we have the industrial analogs, natural gas storage, CO_2 EOR, liquid waste disposal. All of these things are commercial processes which are ongoing and have been significant technology base-developed, and safe operating and secure operating procedures.

We also have the ongoing projects, such as Sleipner and Weyburn, in which people are making many measurements to demonstrate the security of the storage.

Nonetheless we cannot avoid the issue of risk of leakage and its impacts. We also know that if you randomly put a hole in the ground, in fact, CO_2 fluids can come back to the surface.

There's two ways that I think are two

important elements of looking at the risk of leakage. One of the elements is to sort of take a global look at the effectiveness of storage relevant to what we want to achieve with atmospheric stabilization.

And this means that we look at the amount of CO2 which we need to store in order to maintain a certain stabilization target, such as 350 parts per million up to 750 parts per million. And then we evaluate how much leakage we could withstand in order to meet those stabilization targets.

And that kind of analysis has been done, and the graphic here on the left is a synopsis of that. It was done by a colleague of mine, Sally Benson. The results of which indicated that in order to meet stabilization targets, atmospheric stabilization targets, we probably have to have geologic sequestration leakage rates of less than one-tenth of a percent on an annual basis.

There's plenty of data to indicate that we can find geologic formations such as reservoirs which have contained oil and gas for geologic time that would enable us to meet this sort of target.

More difficult problem may be the impact of localized leakage. Localized leakage, which may occur due to wells, abandoned wells, or perhaps due to faults which we had not detected, or exist as conduits from the subsurface to the surface.

It's clear from data and natural leaks which have been documented that you can have localized ecological ecosystem impacts at leakage rates much lower than a tenth of a percent per year. On the other hand, I think that these sorts of impacts can be mitigated. We have technologies available which can mitigate the impact of these localized leaks. But nonetheless, it is an issue that we must deal with.

So what can we do to manage risks, and particularly thinking now about these localized leaks. Risks can be managed by careful site selection. We know from experience what constitutes a good secure geologic reservoir. Sound operational practices for well construction and injection control. Effective monitoring. Remediation strategies; and effective regulatory oversight.

The graphic on the right is simply an example of a methodology which we developed as part of the WestCarb effort to screen sites based on potential for leakage.

Turning now to monitoring. There are many reasons why we need to monitor and should monitor geological sequestration projects. We need to confirm the storage efficiency and processes. Insure effective injection controls. Detection of the plume, location and leakage is essential.

We have to insure worker safety and the public safety. We need to be able to design and evaluate mediation efforts based on what we are learning from our monitoring.

Detect and quantify surface leakage. We can't do anything until we detect it at the surface. Provide assurance and accounting for monetary transactions, settle legal disputes. Many reasons to monitor.

And we have a substantial portfolio of monitoring techniques already available. The oil and gas industry has developed a tremendous amount of technology which is directly applicable for this. Seismic and electrical geophysics, well logging, hydrologic pressure tracer measurements, geochemical sampling, remote sensing, sensors, surface flux measurements.

It is very encouraging to find some major companies such as Schlumberger, now developing business units which are focused on sequestration because clearly we need to take these portfolio techniques through the commercial sector and apply it specifically to sequestration. So it's very encouraging to see this already underway in the commercial sector.

The graphics on the right are just one demonstration of monitoring using seismic technology. And the cartoon on the right is once again related to this North Sea Sleipner CO_2 storage project. And it shows that the CO_2 is injected into a utsira formation about 1000 meters below the ocean floor. And then they used 3D, that is three-dimensional seismic profiling to monitor the plume. And that is in the pictures, the bright red being the location of the CO_2, derived from seismic measurements that were made at different times.

And then one more, more detailed technical result. With a geophysics background I had to show it. VSP is vertical seismic profiling; it's a particular geophysical technique in which you put seismic sources -- sources of seismic energy on the surface of the earth, and then you put receivers down the well in order to receive the signals from that surface source.

The reason I show this is that as a result form a recently completed test in Texas in which a very small amount of CO_2 was injected into the saline formation, 1600 tons only. In the scheme of things 1600 tons is a very small amount of CO_2.

And the two there, you can see two things labeled preinjection and postinjection graphics there. And you can see the difference in colors at the location of what's called the Frio reflection. So what you're looking at here in these two panels is reflections of the seismic energy from the deep subsurface. And you can tell that as the colors get brighter over on the right panel, it is the result of the existence of the CO_2 in the subsurface.

The importance of this is that we have now, are building confidence in using this portfolio techniques to show that we can monitor the location and spread of the CO_2 in the subsurface, even at very small quantities. And, of course, this, then, harkens back to the importance of looking for leaks.

Another comment I wanted to make is related to the cost of geologic sequestration, captures the biggest portion of the cost of geologic sequestration. And this has been discussed a little bit in previous talks. Using current technology captures 70 to 80 percent of the total cost.

Some of the estimates made by EPRI for western coals are indicated in the table below. And they are, you can tell, categorized by type of technology we have. The amine technology as the conventional technology, compared in fact with gasification and possible application of oxyfuel technology with the CO2 avoided costs below that, running from $30, $50, even up to $70 per ton avoided.

Clearly, there's work to be done. New approaches are being studied, both in terms of capture and in terms of processes which produce concentrated CO2 streams ready for sequestration. Not requiring some of the expensive capture techniques like amines.

The other portion of the cost equation

for geologic sequestration, which until the last couple of years was a great big question mark, was for monitoring. People have often said, well, goodness gracious, we have no idea what it's going to cost to monitor.

Until a couple of years ago, Sally Benson and colleagues did an analysis of that, looking at the various phases of operation of a geologic sequestration project. The preoperational phase in which you are basically exploring the formation and convincing yourself it's the proper place to put it. The operational portion in which you are -- during which you are injecting the CO2. And then a closure period after operations in which you monitor the site in order to assure yourself that the CO2 is doing what you thought it would do, and staying where you thought it would stay.

And you can tell the sort of numbers and types of technologies that were included in this assessment. And the magnitudes of the costs associated with that

The bottomline being if you were to look at the costs of monitoring either an enhanced oil recovery project with sequestration, or a saline formation sequestration project, you're talking about tens of cents per ton of CO_2 for the monitoring costs.

In our opinion, monitoring is not going to be a substantial -- the cost of monitoring is not going to be a substantial roadblock to carbon storage in the subsurface.

A comment on remediation. There's substantial experience in dealing with leaks in the subsurface. So, once again, it's not an area in which we have nothing to say, if you will, about what might happen if things do go wrong.

Certainly there are technologies for dealing with leaking wells. The graphic on the upper right is in reference to the famous problem in Africa with the overturning of the lake and the remediation action taken there, which was simply to pump the water from the subsurface.

There's significant technology available to remediate groundwater problems, which could be applied to CO_2 if necessary.

This is an area where more research is needed. The message here is that we need to do more, but we are not at a loss about what to do.

Final comment about pilots. Pilots

provide the regional knowledge base essential for large-scale implementation. Pilots demonstrate the best sequestration options. You need technologies and approaches in the region.

We need to have a number of pilots going on throughout various regions to look at the unique issues associated with each region. They provide the site-specific focus for testing of technologies, defining costs, looking at leakage, gauging public acceptance, testing regulatory requirements and validation of monitoring methods. All of these things have to be done as part of the pilots. They're an essential next step to take.

More specifically, what can we think of as the sort of the technological issues that we need to look at next and relate it to sequestration. Reconciling and revising capacity estimates. I noted that these are not trivial things to do. They are locally -- need to be done locally. So we need to do more work to gather that information together.

Develop criteria for site selection. Essential to get the best sites. Screen the sites that work; we know what kind of sites should work. We simply have to have the site selection criteria in place to do it properly.

Best practices for well construction and injection control. I mentioned, once again, the issues of potential leak paths through abandoned wells as probably one of the most significant potential issues related to leakage that we must have under control.

Monitoring and verification protocols are needed. Mitigate strategies, as I noted. And then field testing to build experience.

So, thank you very much.

PRESIDING MEMBER GEESMAN: Thank you, Dr. Myer. I wonder if you could elaborate a little bit on how you would optimize enhanced oil recovery for CO2 storage, and what the consequences of that optimization on the enhanced oil recovery would be.

DR. MYER: So what you want to do is you want to minimize the amount of carbon dioxide which basically is recycled. So during the normal process you get CO2 coming through to the production wells. And it's simply separated -- now it's simply separated out and put back in.

Stanford actually did a two-year study to look at the options for doing this process of optimization. And found that there are methods in which you monitor what's the gas-to-oil ratio in the producing well in an operational sense. And you use that information then to guide the amount and pressures of which you inject CO2. And via that method you can, in fact, sort of minimize the amount of CO2 that has to be recycled. And then optimize the process.

So what I mean by optimize is to enable you to store as much CO2 as you can, while at the same time, not diminishing the amount of oil that you can produce from the process.

PRESIDING MEMBER GEESMAN: Or the rate at which you would produce such oil?

DR. MYER: Correct.

PRESIDING MEMBER GEESMAN: Thank you.

ASSOCIATE MEMBER BOYD: Larry, when do you anticipate WestCarb field tests to take place?

DR. MYER: We're starting -- the planning process for the first field test will start in October. I expect it'll take a year to get into the field. So that would be a year from this October.

ASSOCIATE MEMBER BOYD: Thank you.

EXECUTIVE DIRECTOR LARSON: I have a

question. In terms of sequestration, doesn't it have to be -- I mean we have to think about this as we build new coal-powered plants. In other words, if we're -- that should be a cost, or a part of the cost of building a new coal power plant. And so the sequestration points have to be either close to where you're building the new plant, or somehow there has to be a transportation system of carbon dioxide. Is that right? And would it cost --

DR. MYER: That is correct.

EXECUTIVE DIRECTOR LARSON: -- quite a bit more?

DR. MYER: Transportation is, and in the scheme of things it's not considered to be a major component, but, of course, if the pipeline gets too long it begins to build up costs.

That's one of the things, for example, that we are looking at on a regional basis. We have cost curves developed as a function of the distance that it needs to be transported.

EXECUTIVE DIRECTOR LARSON: So when you build a new coal power plant you have to have in mind a storage space for carbon dioxide that's close enough to the plant, and it has to be large enough for the plant's capacity over a long period of time.

DR. MYER: That's right.

EXECUTIVE DIRECTOR LARSON: I had another question, also. Isn't there -- I don't know if it would matter in the matter of coal, but also aren't there other technologies like deep sea sequestration that the University's been looking at in terms of disposing of carbon dioxide?

DR. MYER: Yes, there are. There's a significant amount of research in looking at the impacts of putting carbon dioxide into the ocean. I think there's not much focus on thinking about it as a near-term viable technology for sequestration. There's, certainly though, significant research ongoing to look at the impacts of putting CO2 into the ocean.

The other viable near-term technology which I didn't mention was terrestrial sequestration. It is certainly an option for storage of carbon. We usually don't talk about it with regard to an option for power plants for a couple of reasons.

One is that power plants aren't the only producers of CO2, so if you want to sort of have a scheme for storing CO_2 you might think of using terrestrial to store the carbon from dispersed sources.

The other thing is that terrestrial probably does not have the -- offer the storage capacity needed for the amount of CO_2 that we're speaking of.

PRESIDING MEMBER GEESMAN: Thank you very much.

MS. MUELLER: Kelly had to step away for a few minutes so I will be introducing the next few speakers. I'm Marla Mueller and I work for Kelly in the PIER program environmental area.

Our next speaker is Dr. Joseph Strakey. He leads the Colin Powell R&D programs for DOE's National Energy Technology Laboratory. He is responsible for implementation of a national R&D program to develop advanced coal-based energy technology.

The program encompasses a broad range of advanced technology development initiatives in the areas of coal gasification and combustion technology, environmental control technology for existing plants, hydrogen and syngas, carbon sequestration, gas turbines and fuel cells.

Dr. Strakey will be presenting on the U.S. Department of Energy programs in the Strategic Center for Coal.

DR. STRAKEY: Thank you. Commissioners, Distinguished Panelists and Guests, it's a pleasure for me to be here today to talk about coal in California. That doesn't happen too often.

Just as a way of introduction, I know some of you are familiar with the National Energy Technology Laboratory, but for the benefit -- especially for the benefit of the guests, we're part of the Department of Energy under the Office of Fossil Energy. We primarily do fossil energy research, but also some energy efficiency and renewable energy type work. We have about 1100 employees divided mostly between Pittsburgh, Pennsylvania and Morgantown, West Virginia; with a smaller office in Tulsa, Oklahoma, and a few people in Alaska.

We primarily sponsor outside R&D with various organizations, industry, academia, research organizations, and cooperate with organizations such as the California Energy Commission in advancing some of the technologies that we see will be important for our future, and I'm sure you see will be important for California.

I think the last project that Larry talked about is a good example of cooperation between DOE and the California Energy Commission. It's been an excellent project.

The R&D program is really addressing the kind of technology that we'll be implementing around the 2015 to 2020 timeframe, so it's pretty far out. So I'll mostly be talking about the research that we have in the pipeline to address some of these problems.

Predicting what kind of an energy scene we'll have in 2020 is not an easy matter. I'm glad I don't work for the energy information part of DOE. They have a tough job.

Some of the things that can affect our energy future I have shown on this slide here. LNG is really an important one. The slide on the upper left was published in The Boston Globe and it shows an LNG tanker threading its way through Boston Harbor in front of and behind various residential housing units. This came out around the same time that Sandia released a report about the impact if one of these blew up in Boston

Harbor. And needless to say, the people on the east coast are hoping that all these LNG terminals are sited in California rather than on the east coast.

Another trend here is -- and by the way, that's public perception that can impact what happens with LNG, as opposed to reality. And it could be very important in determining how much LNG we import. And I'll get to that in a minute.

There's another trend called peaking of world oil. And a lot of energy experts are being listened to these days because they're projecting that conventional oil worldwide will peak in maybe from the next couple of years to maybe to 2016. Sometime in that timeframe oil will peak. It doesn't mean we run out of oil; it means it starts -- conventional oil production will start on a downslope.

Meanwhile you have growth in demand from countries like China and India, which are affecting price. And I think we're all experiencing the price issues with respect to liquid fuels these days.

And the third, the really big one is concerns about stabilization of CO_2, stabilization of greenhouse gases in the atmosphere. That's a bit unknown what will happen from a regulatory point of view there, but a large part of our program is really directed at addressing those kind of issues.

We're looking primarily at zero emission coal technologies, not just in terms of SOx, NOx, mercury and byproducts, but also carbon dioxide. And by zero emissions we mean typically 99 percent removal of sulfur; getting NOx down to the best that you could get with natural gas technologies, namely below 3 parts per million emissions; typically 95 percent mercury reduction; and 90 percent or better CO2 reduction.

This is some of the EIA projections about the future for natural gas and coal. And natural gas is in the light blue and coal is in the orange in this graph. You can see that they don't show a big change, big increase in renewables, which is in the blue bars.

So the future, according to EIA, is really being determined by natural gas and coal. And the tradeoff between those two fuels is really determined by things like how much LNG that we will import. So, coal can play a very important part in our future.

Go to the next one. It deserves some attention and looking a little deeper at some of the assumptions underlying the EIA forecast, and how they've changed over years.

The AEO-02, at the bottom of this chart, is the projections that EIA made in 2002 going up to 2005. And you can see that they're projecting that the amount of LNG that we'll be importing is increasing substantially. And we consume about 22 tcf or so in the U.S. now.

In '02 the EIA said a lot of this gas is going to come from Canada. But now those forecasts have been revised downwards, since the gas is going to be used primarily in Canada. And a lot of the additional gas would come from LNG.

If you look at the forecast on the top that Exxon Mobil makes, they're even more bullish on LNG than the EIA forecast. And they're showing that by 2030 that 24 percent of the gas used in all of North America will be imported from offshore. That may give you pause; I know it does me.

And if we look at some of the forecasts about growth in electricity demand that EIA makes, that's also interesting. And if you look at the chart up to about 2005, over the past 30 years or so there's been a strong tie between electricity production and growth in GDP. These curves track each other pretty well.

Since about 1975 or so total energy consumption per unit of GDP has fallen off. Those curves have separated as we've become more efficient.

EIA is projecting that in the '05 forecast that GDP will separate from electricity production and follow the trend in the last couple of years. And if you extrapolate that out to 2025 you get to where EIA is projecting. If they're wrong about that, you'll need about 46 percent more electricity, if those curves do track each other. And where does that come from? It's likely to come from sources like coal or LNG.

The reason -- perhaps I should have mentioned it -- the production of gas in the lower 48 states has been relatively constant over the last decade or so; in fact, it's decreasing slightly. So that's why the imported LNG becomes important.

We've got plenty of coal. I think we've

all seen this already. That's been brought out this morning. Enough for at least 250 years, plus or minus, depending on whose estimates you believe. And it's a lot larger than our domestic supplies of natural gas or oil.

And as was pointed out this morning what we see as growth in the use of western coal, and that's projected as we move into the future, to increase substantially.

A lot of the work that we're doing is looking at the technologies to allow western coal to be used more effectively, like in the gasification program where it has been problematic primarily because of the high moisture content. I'll get to that a little bit later.

This is an interesting graph; it dates back to 2001 and shows that the cross-over between coal and your choice whether you would put in a coal plant or natural gas, and the numbers are a little bit dated. The coal plant, coal prices now are a little bit higher than that in the east. The western coal prices are still pretty low; they're less than $1 a million Btus.

But natural gas prices now, we just looked it up on the web at lunchtime, and in New

York it was $10,45 a million Btus, which is off the end of this graph. So you can see that now if this chart is right, that your choice, if you're going to build a plant, would probably be coal.

So what are the challenges that we have to address to use all this coal, and by 2020. We're looking towards near-zero emission technologies for coal. And that's what I mentioned before, the kind of emission levels we're looking at.

An effective way to manage CO_2, to capture it and sequester it permanently, as Larry just talked about. We're very interested in increasing the efficiency of these plants, because not just for the sake of using fewer resources, but also because you are then producing less CO_2 which has to be sequestered, and that lowers your overall cost.

Water use may be a big issue 20 years out, 15 or 20 years out. And that's an area that we have a small program in, but that's hopefully will be increasing our look at how we can more effectively reduce water consumption and use other impaired waters to meet the needs required by coal gasification, for example.

Having flexible feedstocks is very important, being able to use different coals, biomass, petcoke and so on in these technologies. Being able to produce high value products like Fischer Tropsch liquids along with power, for example, is important. And being able to site these plants at a large number of locations in the country, of course, are important considerations.

And, of course, last, you want this to be cost effective and competitive with other technology options.

Carbon capture from these plants is getting a lot of attention. Carbon capture in the sequestration in the popular media, "The Scientific American" just had this cover, I think it was in July. And part of the reason is that the capacity for geologic storage alone is, in the world is pretty enormous. If you look at these charts, this looks at the maximum that people project, not necessarily the low end or the most probable.

But no matter which way you look at it there's a vast capacity for storage of CO2 in geologic formations. Of course, the first ones you would go after are the high value, or value where you can produce some value like in enhanced oil recovery. But for high volume sequestration around the country to be able to sequester in areas where you want the power you have to look very seriously at injection in deep saline formations which underlie a large part of the country and are available where you might want to site power plants.

Cost is a problem for a couple reasons. One is that you capture CO_2, you have to add capital costs. And there's a significant energy penalty in taking the CO_2 out, compressing it and injecting it into the ground. The cost is in the compression and in the separate step.

So what you've got is you're adding equipment and you're getting less megawatts out of the same plant. So that drives up the cost, increasing the numerator and decreasing the denominator. So the cost of electricity tends to go up significantly when you add CO_2 capture.

Using the technologies that you have available now, however, we see that in the future we can lower those technologies. And the goals of our program, if you look at the graph on the right, the light blue is where we're trying to go. We don't have all the answers on how to get there yet, but we're getting closer.

I'm going to talk about three pathways to get to zero emission coal. You've heard some of this already in different forms. Gasification is the one we've talked about a lot this morning.

Post-combustion capture is also a good possibility, either from existing facilities or probably more likely from new highly efficient super critical PC boilers where you produce less CO_2 and the capture then becomes a smaller part of the total cost.

And oxycombustion is another approach where you burn coal with pure oxygen, so that the product coming out of the back end is relatively pure CO_2. So it simplifies significantly the cost and technical aspects of capturing it.

This shows a couple different pictures of technology options for gasification for oxycombustion. It's actually a hybrid oxycombustion that the California Energy Commission has been sponsoring with Clean Energy Systems, as well as DOE. We've both been funding this project at different stages.

And the third is a tail-end scrubbing

technology at the University of Texas where they're looking at ways to enhance tail-end scrubbing and reduce the cost of separating CO2 at the back end of a power plant.

The budget for the program is about $300 million for the research part of the program. And you can see that sequestration is a significant part of that. It's the most rapidly growing, as well as work that we're doing in distributed generation, which is now being really directed toward central station applications in zero emission configurations.

With the exception of the part, innovations for existing plants and the $19 million, the rest of this program is really primarily devoted toward zero emission technologies.

FutureGen is the big one, the 900 pound gorilla, but it's in its early stages and so we're only spending $18 million or less this year.

There's also the Clean Coal Power Initiative, which is the big demonstration program. I'm not going to get into that in any detail today at all. But, last year, in 2005 there was $50 million appropriated for that.

And since the emphasis in that program has been towards IGCC we tried to save up about $300 million before we have another round because when you cosponsor a large demo of an IGCC you need that kind of money. And we have to have all the money in the bank, basically, by statute before we can award projects under that particular program. So that's likely -- the next round of that is likely to occur in 2007, in terms of issuing a request for proposals.

Gasification is a key part of the R&D program. And we're looking at a number of advanced technologies. One, to improve the performance of various parts of the gasification system; as well as to improve the reliability. The reliability issue was discussed a little bit this morning and the problem there is that right now you need a spare gasifier. That adds significantly to the total cost of the plant, 10 or 15 percent of the capital cost.

Overall, these gasification plants are about 20 percent more expensive in terms of cost of electricity than PC plants. So, you have to think hard before you choose an IGCC unless there's other incentives for you to do so.

Some of the technologies we're working on are the oxygen membranes to improve the performance and efficiency of separating oxygen from air for the gasification.

Gas stream cleanup to remove sulfur and other components. Membrane separations to separate hydrogen and CO2, which are a lot more promising than some of the ways we do it now. We have a program on sequestration to look at what to do with the CO2. And a lot of work on the power end, on turbines and also a little bit on looking at various options for producing other products that add value to a gasification plant.

Just to mention a couple. This is probably the big project that we have. It's Power Systems Development facility, which is in Wilsonville, Alabama. When we have that -- that's run by Southern Company Services for DOE.

A number of other organizations are involved in that, including EPRI. And that's developing technology much more efficient and cheaper gasification scheme which is especially applicable for the western coals.

This technology is the basis for that plant that was mentioned this morning in Orlando;

280 megawatts. That will use Powder River Basin coal.

And the next thing we plan to look at here is some high moisture lignite from North Dakota. So we are looking seriously at using this kind of technology as a way to handle western coals. We're spending about $25 million a year on that facility. It's about half of our gasification program.

Recently we started work with Rocketdyne and that's recently been acquired by United Technologies. And they have an advanced gasifier concept. And it uses essentially a water wall instead of the refractory wall that people have used in other gasifier designs.

It's a rapid mixing plug flow reactor. And it promises to be a lot smaller and a lot cheaper than the existing slurry-fed type gasifiers. And can also use dry feed. It has multiple injectors instead of a single coal injector in the gasifier, which should improve reliability significantly. And it promises much higher carbon conversions, the graph on the right. So from the cost budgets it does look a lot better than the existing slurry-fed gasifiers.

This may be the first big improvement in slurry-fed gasifiers like the E-gas or the GE gasifier in the last 40 years.

We're also looking at sulfur cleanup. This is a unit that we now sent to Eastman Chemical in Kingsport, Tennessee. It was originally at Montebello. We got this unit built and just up and just started testing and then they closed Montebello. So we missed all our milestones and packed it up and sent it off to Kingsport where they're doing a great job in getting it back online. They're doing the final checkout of instruments and wiring and piping and so on. So we expect that this will come back online in September to maybe early October.

And it'll test a dry high-temperature sulfur removal technology, which combined with some other things that they're looking at, can get you essentially a big boost in efficiency and lower costs.

I mentioned some of these technologies that we're looking at, and we've done cost studies of various options for reducing the cost, to try and get to that 10 percent increase in the cost of electricity goal that we have for our program.

And this chart shows some of the options that we've examined to get there by looking at advanced ways to clean up H2S and CO2, water-gas shift membranes built into it. And ultimately, even chemical looping technologies for gasification, which are pretty advanced and complicated, but they promise to get pretty close to the goal. But we're still about 5 percent over our final COE decrease goal.

If you make hydrogen, which is pretty much what the concept of FutureGen is, or other zero emission IGCC plants, and burn the hydrogen in the turbine it's not just a no-brainer. You have to do some modifications to the turbine, and it has an impact.

When you burn hydrogen you tend to produce a lot of moisture in the combustion products that go through the turbine. And they increase the heat transfer to the blades. And as a result, since you're really at a high temperature already, the way they approach this generally is to decrease the turbine inlet temperature and dilute -- well, they dilute the hydrogen with other gases available in the process like nitrogen.

And as a result you take a hit on efficiency of anywhere from maybe 1.5 to 3 points on the efficiency of the turbine. So our program is really looking at how do we get that efficiency back. Increase the turbine inlet temperature through a variety of technical options; improve thermal barrier coatings and so on.

And also looking at some of the other problems with hydrogen turbines. NOx is not an easy problem. When you burn hydrogen with air containing nitrogen, there's a tendency to produce a lot of NOx, a lot more than you have with burning syngas from the normal IGCC with air.

So, looking at how we change burners and use catalytic processes to reduce NOx is a key part of the turbines program.

We had a solicitation for the turbines program which is closed now. And we're doing the final steps of announcing the awards. I think this announcement will significantly change the way the turbine program was going. It's sort of a new direction for the turbine program and it's in these categories that you're looking at here. Probably make announcement of those awards, I'm guessing within a week.

So a large part of it is looking at those hydrogen turbines, the kind of thing we would put into FutureGen. But we're also looking at oxy modifying turbines to adapt to oxy fuel combustion where you burn syngas or hydrogen with oxygen. And that has a significant impact on the high-pressure, high-temperature requirements that you would place on a turbine.

And we're also asking for proposals in the area of smaller turbines that might burn hydrogen. The kind of turbines you might have in an industrial configuration where you get hydrogen from another plant, from a coal gasification plant or wherever, if it's pipelined into a major user.

There's a category in there of looking at how hydrogen can be added to other fuels like natural gas to reduce emissions, as well. And so on.

And the last one is -- may be interesting to you is looking at novel concepts for the compression of large volumes of CO2 like you might have coming out of the back end of a power plant. And I know the California Energy Commission has been involved in some work on novel compression techniques using basically supersonic compression technology.

Another area is hydrogen and there's a bunch of projects. I'm not going to go into them in any detail. But we have one which is pretty interesting with ELTRON, that looks at a membrane separation for hydrogen that's very promising. They get very high fluxes of hydrogen through this membrane. And if you can have a hydrogen membrane and put that in the tail end instead of these wet absorption processes like amines or selexall, this is potentially a deal-breaker. And it can separate at high temperature these gases and promise much higher efficiencies.

There's also other work in the hydrogen membrane program using membranes that have been declassified from basically the gas -- nuclear separation technologies at Oak Ridge.

Fuel cells is another area in the program. And you're probably familiar with this to some extent. We've been working on developing high temperature, solid oxide fuel cell technology for small applications, residential, commercial, premium power and so on in the near term.

But ultimately over the ten years, up to about 2010 to 2012 in that timeframe, getting the cost down to $400 a kilowatt for these technologies, which would make them attractive in a wide variety of applications. So then you get the kind of purchasing power and cost reduction that comes with high volume.

And we think that we're getting close. We're ending the first phase of this program and part of that is the contractors that are involved deliver to us the fuel cells and we run them through the testing program we have to qualify them to go on to the second phase. That will occur late this fiscal year on the first two contracts.

It's looking pretty good. We think that, you know, if they pass the test they'll meet the cross-targets, at least the initial ones that we will look at.

And if they're promising in the smaller scale, we think that this may be an attractive option for the power island in the gasification scheme. And that means growing these things significantly. Aggregating them, making them bigger, running them under pressure, combining them with turbine technology so that you can recover the pressure energy and so on. And then they may be cheaper and more efficient than turbines for producing the electric power.

The other big advantage they have is that in the process, it's just inherent in the electrolyte in the way it works, it separates the CO_2 from the air. So instead of ending up with CO_2 diluted with nitrogen, the CO_2 migrates over to the fuel side of the cell and ends up there where it's easier to capture. It's basically a built-in separation technology. So they can be an effective way to do zero emission power generation when combined with a clean fuel gas.

These are the teams that are involved, Siemens Westinghouse, FuelCell Energy and so on, Delphi, GE, Cummins and Acumentrics. And they've made some good progress in that program. And they're producing small cells now, typically 3 to 10 kilowatts, for testing.

And this is a graphic that shows what will happen as we scale these up. We will aggregate these things and put them into larger plants. Hopefully we'll have a multi-megawatt unit ready in time for testing in FutureGen, which will come online around the 2011 to 2013 - 2015 timeframe. So we'd like to run a slipstream test with this technology at FutureGen.

I already covered the WestCarb partnership in sequestration. I'll skip through this kind of briefly. But that's been a growing part of our program. And Larry already mentioned Sleipner and Weyburn where large volumes of CO2 are being sequestered, over a million tons a year.

FutureGen will also be over a million tons a year. And that's about all that's on the horizon in terms of large volume CO2 injection tests, with the exception of what might be done commercially for enhanced oil recovery.

Again, our goal is to get to 10 percent COE reduction by 2012. And for existing type technology, PC plants, 20 percent increase in the cost of electricity in that timeframe. And better later on.

The program's been growing substantially. For a period there it was doubling every year, which made our technology managers pretty happy. But it's growing to the point where it's probably going to be in the $65 million range this coming fiscal year.

And you can see by the pie chart that it's divided largely into sequestration and capture. The regional partnerships are a growing part of that pie. And a little bit working on breakthrough concepts and some other gases as well as CO2. It is a priority in our program.

By the way, it's gotten significant industry cost-share, 36 percent, which is probably surprising to a lot of people when you think about sequestration. That shows that people are seriously interested in it.

There's seven regional partnerships, WestCarb being one of them. And this map was a lot smaller when the program first started, but now it's expanded into Canada and so on, and covers most of the U.S., with the exception of some of the northeast states where sequestration is not likely to be a likely option anyway because of the nature of the geologic formations they have in that area anyway.

Larry mention Frio, which is one of the kinds of the things that we want to do more in the second phase of the regional partnerships. We want to run a number of injection tests to verify some of the models and theories that people have about sequestration.

Unfortunately there's not enough funds

in the program to do big, multi-year, million-ton-a-year injection tests. But these kinds of tests will do a lot to validate the concepts and the potential sinks that people might look at.

And then it kind of all comes together in FutureGen. And we're working actively on that with the Alliance. It's taken awhile to get it going. I think when you look on our side the requirements DOE places on a billion-dollar project and the environmental aspects and so on, it's kind of daunting.

And it's probably equally daunting on the part of the Alliance to get nine or ten CEOs together and agree on something, and all the legal papers that go with it. So, it's moving forward, and we expect that, you know, we'll move into the more active phases very soon.

It's a 275 megawatt plant. We intend that it will also produce some hydrogen. We'd like to see it sequester and probably more than one sink, maybe like a saline aquifer and EOR, so that we get data from more than one potential sink.

And it'll only run for a few years because the cost for us to do more than that would be prohibitive.

That kind of thing, though, will lead the way, I think, to other plants in the U.S. Somebody's got to do it first. This may be the first big coal plant that does CO_2 capture and sequestration.

Just a few words about oxyfuel and other pathways. We've been talking primarily about gasification, but there are other approaches, and they may be, in fact, pretty promising.

Oxyfuel is basically you put, you have a boiler, probably a new design, probably super critical, and instead of putting air in you put in oxygen. And you dilute that oxygen with CO_2 that's recycled from the process.

Separate the particulates in an electrostatic precipitator at the -- well, in the middle of the chart here -- and then a small volume of CO_2 goes through the flue gas cleanup system to remove sulfur and other impurities. And then separate out the water, which would come out in the FGD system anyway. And compress the CO_2.

This kind of concept can have some potential impact, especially if we can reduce the cost for oxygen consumption. And that's one of the areas that we are working on.

I should mention that in terms of gasification versus combustion approach, our funding is about two-to-one on gasification. But there's also a huge amount of work that's common to both, that's equal to almost both of them put together. So that things like the sequestration is not specific to gasification or combustion. It applies to both.

And oxycombustion can give you lower volumes of NOx and lower volumes of flue gas, reduced NOx. Because you're burning with oxygen you tend to get -- it promotes the oxidation of mercury to an oxidized species so it's easier to capture in the tail end. And you increase the percentage of CO2 in the product gas significantly, so it's easier to capture the CO2.

These can lead to a significant reduction in the cost to capture CO2. Some of the chemical looping processes, I think, are the extreme in terms of oxyfuel type approaches. And with them we see that you can get close to that cost goal of 10 to 15 percent increase in cost.

But they're really far out there; they involve multiple flow loops, typically like five flow loops all coordinated together which is an engineering challenge. So it's nowhere near as far along as some of the gasification concepts.

As we talked about in the beginning, a lot of plants will require repowering or replacement by 2020. That's a huge amount of coal plants that may be in place. And if some of these other things come to fruition like we don't import as much LNG, it'll be even greater.

So there's an opportunity to bring coal into the market primarily in that timeframe through new plants. And so we have to have the technologies ready by about 2015 to meet the potential targets for implementing these plants.

In closing, I think I'm trying to make a case that coal may be playing a key role in our energy future. I should say that the existing fleet is not going to go away. Those plants typically last 50, 70 or more years. So we have to pay attention to what we do with those plants, as part of our overall strategy to meet our environmental goals.

We need some of these new plants online soon. Hopefully some of the provisions of the Energy Bill will get us some experience with IGCC on the ground, so that we can start to lower the cost and reduce, for example, like the amount -- that you won't need a spare reactor; through experience you might be able to get that liability increased.

And we think the R&D that's in the pipeline now will be important for our energy future. And there's all kinds of information on these 800-or-so coal projects on our website.

Thank you.

PRESIDING MEMBER GEESMAN: Joe, thank you for being here today. I wanted to ask you a question in terms of your sequestration program. You set some very aggressive goals in eliminating the cost penalty on pulverized coal plants. I wonder if you could elaborate a little bit more on which aspects of your sequestration program you think has the most promise directed to pulverized coal plants.

DR. STRAKEY: Which has the most promise? I think the oxyfuel route for PC is probably -- this is a personal opinion -- the most promising. And if you can combine oxyfuel with super critical plant designs, that this may be, overall, the best way to do it.

I think that if you look at Europe and you see that super critical plants, combined with tail-end scrubbing, may be a very competitive option with IGCC.

I guess my own thought is we have technologies in the pipeline for reducing the cost of oxygen, so if you can use oxyfuel along with capturing CO2 in this concentrated stream, that's the most economical way to go.

PRESIDING MEMBER GEESMAN: Thank you.

VICE CHAIRPERSON PFANNENSTIEL: I just want to make sure that I'm clear on some of the cost differences looking today. Now, obviously you have goals for your research to bring the costs down, but the different -- the cost of CO2 capture I thought you said was a big range, 25 to 100 percent increase in the cost of electricity. Was that what I heard?

DR. STRAKEY: Yeah, on that one --

VICE CHAIRPERSON PFANNENSTIEL: And with the goal of bringing that down.

DR. STRAKEY: Right.

VICE CHAIRPERSON PFANNENSTIEL: And also the gasification was about 15 percent more than PC plant right now?

DR. STRAKEY: Twenty.

VICE CHAIRPERSON PFANNENSTIEL: Twenty?

DR. STRAKEY: Yes.

VICE CHAIRPERSON PFANNENSTIEL: Okay. And the other question that I had earlier that you seemed to be working towards is that your FutureGen of your zero emission plant is about 2020 is when you see that kind of technology coming together?

DR. STRAKEY: Well, FutureGen, according to our plans, would come online around 2011, and run through almost 2015, so --

VICE CHAIRPERSON PFANNENSTIEL: Okay, so it's 20 --

DR. STRAKEY: -- short operating period; it's a little over three years.

VICE CHAIRPERSON PFANNENSTIEL: And so --

DR. STRAKEY: And so that technology should be --

VICE CHAIRPERSON PFANNENSTIEL: -- the technology should be commercially available by 2015, is that what --

DR. STRAKEY: After 2015, but by the time you got to make the choices, do the design and so on to get a plant online, it will probably be about 2020.

VICE CHAIRPERSON PFANNENSTIEL: Thank you.

DR. STRAKEY: Okay, thank you.

MS. MUELLER: Our next speaker is Steven Jenkins. And he is a Regional Leader of the Power Business Line for URS Corporation. And Mr. Jenkins had worked for Tampa Electric during the design, construction and startup of the Polk IGCC plant.

MR. JENKINS: Good afternoon. Thanks for inviting me here. I did notice that this morning Stu Dalton, as part of his speech, had a slide called "What Is Coal"? So, I thought I ought to bring one --

(Laughter.)

MR. JENKINS: -- because I'm not sure that anybody in California has seen one before. It's a lump of coal. It's kind of like a snowflake, every lump is different and they're all pretty. So, I figured one piece was enough to get through the TSA screening this morning. But, share that amongst yourselves. There's a lot of energy in there, and that's really the future of energy.

PRESIDING MEMBER GEESMAN: Well, the last speaker said we hadn't addressed coal in California in a long time. Yesterday we addressed nuclear for the first time in 30 years, --

MR. JENKINS: Yes.

PRESIDING MEMBER GEESMAN: -- in this forum, so it's only fair.

MR. JENKINS: What I'd like to talk about this morning are some personal experiences on a real IGCC power plant. I know you've talked a lot and you've shown a lot of pictures, and I thought that maybe this was sort of like when I first heard about the first electric vehicle maybe 15, 20 years ago. And I saw pictures of them, and I know people that were driving them.

And, you know, I couldn't drive my own because there weren't a lot And I thought, well, let me talk to somebody that actually has one. And then I did that and I found what it's like to drive an electric vehicle. And that was really the start of where we are today with hybrid vehicles. What was developed 15, 20 years ago, even commercially, is now, you know, you go to a car dealer you can buy one. And you don't have to just have somebody come in and talk to you about what's it like to drive one of these things.

And so what I'd like to talk about today is what it's like to drive one of these things, to live with an IGCC power plant.

Actually I was born in California, and for some reason we moved from the land of earthquakes to the land of hurricanes. I don't know why. But one disaster or another.

Worked 30 years in the power industry, actually 29 years, 364 days; tomorrow will be 30 years. I spent 25 years with Tampa Electric Company. And my reason for being here today is that I was a former Deputy Project Manager for Polk Power Station, my last big project before I left Tampa Electric and joined URS five years ago.

And wanted to talk to you about some of those experiences, why we did what we did, and what it's like to have an IGCC power plant.

First thanks to two people that helped me put this together, some of my colleagues at Tampa Electric, Mark Hornick, who's the General Manager of Polk Power Station, who lives with this IGCC power plant every day.

And John McDaniel, a senior engineering

fellow that was Tampa Electric's highest honor and highest level of engineers. He actually worked on the Cool Water IGCC project that Ron Wolk and others talked about this morning. He was an EPRI employee for many years. And we were lucky to steal him. And he has, therefore, about 20 years of experience, hand-on, working on IGCC power plants.

There are probably only a handful of people in the entire world that have 20 years experience on IGCC power plants. And he helps it run, and helps it run better day to day.

Well, who's Tampa Electric, and why did we do this. It's a mid-sized utility in west central Florida, about 4400 megawatts of total generating capacity. Not small, not large. About 600,000 customers.

Tampa Electric made a decision to use coal in 1959 after the Suez oil crisis and the company couldn't get long-term contracts for oil from the Middle East. And the company said, fine, we'll use coal. And they said, nobody uses coal in Florida. How are you going to get it.

So the company put together a huge coal transportation system made up of barges on the

Ohio and Mississippi Rivers, a terminal about 50 miles south in New Orleans on the Mississippi Delta, and ocean-going ships to deliver the coal to the power stations on Tampa Bay.

And then backhaul fertilizer. Central Florida is one of the largest phosphate mining areas in the world. And that phosphate is made into fertilizer. And that's what goes around the world. When you buy a bag of fertilizer to put on your lawn, that fertilizer probably came from Florida. Fertilizer that's used to fertilize crops in China and the Soviet Union -- former Soviet Union, fertilizer from Florida. So that backhaul system was put in place to help cut those costs.

This is what it looked like starting with the mines of the Illinois Basin; with the river barges down the Ohio, Mississippi to this terminal south of New Orleans. And then these barges were about 1400 tons each of that beautiful stuff like the lump I gave you. And with tows of 20 to 30 of those barges.

And then transferred to 40,000 ton barges that then came across the Gulf of Mexico to Tampa and delivered the coal to the power station.

And that's been in place since 1959.

When we were looking at Polk Power Station or what the future generation was going to be for Tampa Electric, at the time we had three power plants, Hookers Point, small oil-fired units; Gannon Station, installed between 1958 and 1968; and Big Bend Station, all coal-fired units installed over a 15-year period.

The company had a true commitment to coal as its main energy resource, which kept electricity costs in Florida at or below the national average. And we were 1600 miles from where the coal was mined. Quite an accomplishment.

The company was about 97 percent coal-fired. The balance were some small oil-fired combustion turbines. It also had, along with that, a commitment to environmental performance. We designed the first fuel gas desulfurization system which you install on the backend of a pulverized coal unit to take out the sulfur dioxide. First one in the U.S. designed to produce commercial grade gypsum for making wallboard.

Almost every new home that is built in

Florida has wallboard that comes from a flue gas desulfurization system on a power plant in Florida. We built a new house three years ago. Every piece of wallboard came from either a Tampa Electric scrubber or Seminole Electric scrubber. And I thought 20 years ago they told me that I was nuts for thinking this was the way to go, and here I am building a house made with the same stuff.

Why IGCC. Things were going great. We had regular pulverized coal units, why rock the boat. The early 1990s was the start of the transition of the power industry, and we recognized that there was a need for new baseload capacity about five to seven years off.

We actually formed a 17-member citizen site selection committee. More than half of those people were from environmental groups. We had educators and businesspeople. And we said, this is your resource. You decide where the plant's going to go and what technology we should use.

And they spent two years doing that.

At that time there was also competition growing for development of new baseload plants by independent power producers, but they were all looking at quick-build, combined-cycle units and using natural gas. And you know what those are, you've got plenty of them in California. And you've talked about those kind of technologies this morning.

And we thought how do we preserve our commitment to low-cost coal. Well, then came DOE and their clean coal technology program. Timing is everything. They offered cofunding for new coal-based advanced technologies. We had an opportunity to build new generation, continue our commitment to low-cost coal, and demonstrate state-of-the-art technology.

And big companies like AEP, American Electric Power, and Southern Company said, why is somebody small like Tampa Electric taking on this new challenge. And we thought this is the way to go for the future.

We submitted our application. We were selected. We went to work.

The site selection committee, in the midst of this, said here's where we want you to build your new power plant. In a 4000-acre area that had been previously mined for phosphate. We called it moonscape. It's a surface mining operating about 60 feet down. And you have rows.

And, of course, in Florida you've got a lot of water, and in water, a lot of alligators. So it was interesting moving some of that around to make a power plant.

The only part of the plant site that had not been mined was this little area. That's where we figured was the best place to put an IGCC power plant. I found this old, almost 15-year-old site plan when we were looking at it. The plant was going to go in this little area and all that moonscape to get water to the power plant, we converted those rows of moonscape into an 800-acre cooling reservoir. And that is what is used for all the water. It rains about 52 inches a year in that area of Florida, so there's plenty of water for use in the power plant.

And then we beautified that moonscape by building an IGCC power plant. And that's what it looks like today. I'll get into some of the pieces of it.

You've looked at things like this today. There won't be a test afterwards. And you've looked at IGCC, and I think Stu and Ron and others have talked to you about it, how this works. But, again, crush and slurry the coal; inject it under high pressure into the gasifier; make your synthetic gas; cool it; clean it; send it to the combustion turbine. The heat is recovered. Make steam that goes to a steam turbine generator; make more electricity.

And in cooling the syngas from 2700 degrees down to about 700 degrees you make more steam that feeds the steam turbine. Pretty efficient piece of equipment all together.

These are the pieces of it. Now, that's on about 20 acres right now. And there's some additional gas-fired, simple-cycle gas turbines that have been added for peaking purposes because of all the growth in Florida, we needed some peaking.

Now, this piece here, I'd say, is a combined cycle unit that would run on natural gas. So you'd need all that anyway if you were building a baseload unit.

This little plant here is the gasification plant. The air separation unit that makes the oxygen and nitrogen. And here's the coal silos. And the coal is brought in from Big Bend Station by truck 30 miles away. Those ocean barges that bring in the coal, we transloaded onto trucks; bring the trucks of coal over; and haul byproducts back.

Crush and slurry it. Pump it into the gasification area here. Make the synthetic gas. Clean it. Cool it. Send it to the combustion turbine here, and here's the steam turbine.

Again, this looks pretty much like what everybody's used to anyway, gas-fired, combined cycle. This was the new stuff.

The design basis was 250 megawatts net. Using about 2500 tons per day of coal, the Pittsburgh #8 seam coal, the largest single seam of coal in the world that sits in northern West Virginia and southern Pennsylvania.

And then because of some sulfur conditions and our ability to bring in lots of Illinois Basin coal, higher sulfur, so we designed the sulfur removal system for a little bit higher sulfur.

Removal and recovery of sulfur compounds and sulfuric acid. The phosphate industry in central Florida uses sulfuric acid in making fertilizer. And we were only about 1 percent, a drop in the bucket. But there was a ready market a mile away from the plant. So the trucks load sulfuric acid, off they go. And we continue to sell it to the phosphate industry.

This slag that comes out of the bottom, the ash is in molten form. It comes out; it's cooled; it's quenched; it's crystallized; it's glassy and black. It's crushed and dewatered and sold for use in making cement in southern Florida.

We've got the 800-acre cooling reservoir and zero process water discharge. Sure, we have plenty of water in central Florida, as you saw, but it's important to control your system so it's clean on the air side and clean on the water side.

Permitting issues. This was a real fun time. The agencies had plenty of experience with coal-fired units. Mostly during the '70s and '80s. The Florida Department of Environmental Protection and USEPA Staff were very familiar with gas-fired combined cycle units. So they asked us in one of our meetings, IGCC, is it gas or is it coal. Well, the answer that they gave was, yeah, it's both.

So they said we're going to permit the plant for the least environmental impact. The citizens of Florida require the most efficient environmentally protected plant. We want the best of everything. If it's a coal-based plant we want the tightest emission rate that any coal-based unit can do. We also want it to look like a gas unit.

So we negotiated those permit conditions. But there was no history of IGCC units. The Wabash River Plant in Indiana had been in operation a year when Polk went in service. Cool Water was the only one, and that had been run ten years before, eight to ten years before. So there wasn't a lot of environmental information. We were in a learning experience.

But that was nine years ago. The NOx emissions, they agreed, go with the nitrogen injection, which lowers the flame temperature and reduces NOx, but redo the NOx limits after the DOE demonstration period is over and leave room for NOx controls, the selective catalytic reduction.

So we thought, okay, that's five, six years off, we'll go with it. We negotiated the permit conditions, we went forward, we built the plant.

This is what it was like to drive the car. We hired IGCC specialists, five teams of ten, all with journeyman level skills. They're responsible for operation and maintenance. Typically in a power plant you have operations guys and you have maintenance guys. Here they were multi-skilled, multi-talented. No frontline supervisor. Keep it lean and mean.

One of the best decisions we made was to create, build and use a process simulator that was able to show the control room operators and the operators like flying the space shuttle, except it was huge all around you, every possible consideration. You know, things where the teacher could put in, you're watching it for an hour, things look great. All of a sudden something goes awry, what do you do. And that's how we trained our folks, so that when it was time for plant startup they knew what to do.

Total plant staff is 78 people, those IGCC specialists, our plant engineers like John McDaniel, our administrative folks, general manager. And now that's actually for the IGCC plant plus the two additional combustion turbines operating on natural gas. Pretty small plant for that size.

We started up the combined cycle power block on number 2 oil nine years ago. The first syngas was produced in July '96, and the first syngas to the combustion turbine a few months afterwards. And then we started our DOE demonstration program for two years.

Startup takes several days, and I want to go through this, but I was thinking about this on the plane on the way out. Looking back at other kinds of technologies, when you start a new technology and you're the first one to do it, you have a tough time because nobody's done it before.

You look at flue gas to sulfurization systems. Everybody has them now. They operate great. They go for months or even four years at a time without bringing them down. Twenty years ago, four days was a good operation on a flue gas to sulfurization system.

So I started thinking IGCC isn't that much different than other new technologies that power plants have had to install or retrofit as they change. It takes days, sometimes, to get them started. Things trip off; you bring them back on. You learn; you improve; and you go with it.

But it does take several days to start it up from cold conditions. From hot-start conditions it's a matter of minutes to several hours.

The first year of operation had a lot of challenges. And, again, problems not too different from coal-fired units or gas-fired combined cycle. Driving the car had a few bumps in the road. But we got through those.

There were a lot of little things that contributed to lower-than-expected availability. But we can't say that they could be attributed to IGCC, itself. We had piping erosion and corrosion. You have that in your house. You have that in an IGCC plant. You have it in a regular power plant. We had ash pluggage in syngas coolers. Figured out what was causing them. Fixed it.

Then there wasn't that much experience with GE combustion turbines on syngas. And not that this was syngas-related, but we had problems with the basic combined cycle power plant. You know, there's more and more and more of those, and people are gaining experience; and we know what to look for. And GE's good about fixing those problems. And we got better at it.

We had a lot of nuisance shutdowns. And

that's just, it's like starting the car and all of a sudden the radio doesn't work. And you keep going a little further and then your headlights don't work. And you figure out, because you've got the first hybrid car or whatever it is, how to fix it. And you go on with it.

Year two we had some particulate matter damage to the combustion turbine. Solved it with a syngas filter. The refractory, which is very expensive, several million dollars, that lines that gasifier, because it's operating at over 2500 degrees, is supposed to last two to three years. Only lasted one year. Had a lot of problems the first year.

The sulfur removal was not as high as expected on some sulfur compounds. We had to switch to more expensive lower sulfur coals. Fixed that problem.

And at the same time the plant staff learned how to do faster hot starts. So when that car stalled out you were able to fix it and get running again.

Here we have some syngas cooler pluggage. This is John McDaniel, our senior engineering fellow. This big thing here was --

not John, but the piece of equipment -- would cool the syngas and make steam. It has pipes about three inches in diameter. Well, they plugged with all the ash from the ash that was in the coal. And we had to figure out how to fix that problem. And we did. That was due to changes in ash characteristics. We tried many different coals and petroleum coke over that time period.

Year three, this was a key one. We went from just trying to stay online to finding ways to actually improve it. So, in other words, instead of just trying to keep the car going down the road, now we were going faster and more efficient. And our days were more spent on getting better at what we were doing, not just trying to stay keeping the car on the road.

And interestingly, because of the efficiency of the plant and its ability to use low-cost coal, it had the lowest generation cost in the whole Tampa Electric fleet, and was the first unit dispatched.

We had this carbon and slag issue. The slag coming out the bottom; it was supposed to be saleable, but it had too much carbon in it. And we hired a company that brought in screens and they screened out the slag so it could be sold. And the carbon went back in the process. Later we installed a permanent system to do that. But up until that point we had several thousand tons of slag sitting out there. That was an unexpected little problem. We actually sent the slag with all the carbon in it back 30 miles away to Big Bend. They burned it in their boilers. Carbon is fuel; costs money; we used it.

Year five. It was a really nice time in comparison to the startup years. Things were doing better. A lot of the nuisance problems were solved. We could start up faster. We had fewer problems. But then we had a failure of the main air compressor in the air separation unit. The whole unit was out for a month.

Now, at the same time while that was down we ran the combined cycle unit on the backup fuel. At that same time we were going through those challenges it was time to redo the air permit. The agencies wanted us to install selective catalytic reduction.

It's a technology that works great on natural gas-fired units. Had no experience anywhere in the world on syngas-fired units. We'd worked with them, and GE at the same time was refining some internal methods to reduce NOx, and we came to agreement. And by saturating the syngas with water and/or steam it reduced the NOx to the low levels. And everybody was happy, and we got the new permit and went on.

Year seven, this was kind of key. This is when fuel prices took off. And we looked, we started using petroleum coke. And, of course, our friends at DOE said, well, this was the clean coal technology program, not the clean coke technology program.

But after the demonstration period we realized that we could lower our costs even more and help prove more alternative fuels on gasification. Relative fuel prices. Coal was about 50 percent more than petcoke, but look at natural gas and number 2 oil.

The commitment to coal showed that IGCC was the smart choice that we made seven years before. We had the NOx emission limit resolved; the carbon and slag problem was solved.

But we had some problems with the power block. So, you know, if the left tire wasn't getting you, the right tire was getting you. But we were still going down the road and went from there. And continued to increase our availability.

Year eight was the best ever. Better performance overall, 82 percent onstream factor for gasification; 96 percent availability for the power block; and we were using 55 percent petcoke and 45 percent coal. Very very cost effective. And going along as the first unit dispatched on the system.

But there were seven tough years before that. But, again, it was really the first three years that were toughest, learning how to move that car forward.

Year nine, everything got better. Faster startups. This is really the end of year nine. The plant's now using a blend of petcoke and Venezuelan coal. Because Tampa Electric sits on the peninsula in Florida, we can bring in coal from foreign countries. And we've used in the other power plants coal from Poland, South Africa, Australia, Columbia and Venezuela. So you use what works best.

Plus the Venezuelan coal has some very good ash characteristics, so we don't get the plugging; we don't get the carbon and ash in the slag problem.

But in January the combustion turbine air compressor failed. And the unit was out for 100 days. So, everyone sat around -- didn't really sit around -- there were a lot of things to fix and improve.

So, all the things we'd learned over those previous eight years we started doing during this period of time. And we're integrating the system even better at this point.

So there was a lot of, again, it wasn't how do you get going every day and get that car started every day. Now it's the car's going faster, the car's going better, it's more efficient. Everybody wants to see this car. People from all over the world go to Polk Power Station. Maybe it's because of the IGCC plant, maybe it's because Disney's only 60 miles away. So, a lot -- and in the winter we get a lot of visitors for some reason.

Key availability statistics. These are some of the important things, because a power plant needs to be available. Our goal in the third year was 85 percent availability. And that's the green one.

Well, you can see the first few years were kind of tough. And then we just about hit the 80s. And then over here in 2002 hit 78, 80 percent. Fell off in 2003. And then back in 2004. And 2005 won't look good because of that combustion turbine problem, being out 100 days.

I do note down here that average for coal-fired units is about 87 percent. So 85 percent was a good goal.

One of the things that I've heard some of the folks talk about a little earlier when I came in was Polk only has one gasifier. Two of them would probably solve that problem. So when one's down, the other's ready to go. You keep it in hot start. And for a little bit more capital you've got the ability if one of them's coming down, you start the other one. You keep the fuel going to the combustion turbine and you get that availability over 90 percent.

It is a little bit of additional capital, but if the value of power is high enough it makes sense on an engineering basis and an operations and maintenance basis to put in the additional gasifier.

Companies that are installing these now, or planning to install IGCC power plants throughout the country and looking at two to three 50 percent sized gasifiers, because they realize -- that was that pinch point. That's what kept that car from going on your long trip. And now you've got the spare tire; you've got the spare gas tank; you pay a little bit more upfront, but the car's going to drive for as long as you want it to go. And things are going to get better at Polk Power Station.

Environmental performance. The SO2 removal overall is about 98 percent. NOx, we get 15 parts per million; reduced CO2 emissions, compared to other pulverized coal units, because the unit is much more efficient. Ready market for sale of sulfuric acid. All over the United States people use sulfuric acid. We even sell some of it to municipal water treatment plants that use that as part of their system.

The slag has a beneficial use in making cement. We have low water consumption and zero process water discharge. Pretty darn good way to make power.

The history overall. The first three

years were the toughest, but we made many design and operation improvements. High availability was achieved in some years. Close to the goal and getting better. But we know how to get there.

Continuous environmental performance enhancements. Not just running the plant better, but running it cleaner, and setting an example for other IGCC power plants that are being designed and planned right now.

And experience on 20 different feedstocks. Coals from the east, coals from the midwest, coals from the west, Powder River Basin coals, foreign coals. Powder River Basin, some petroleum coke and even some biomass we blended in. So we've provided a good database for others that are getting into this, and particularly for western coals, which should be of interest in California because they're the closest ones to you.

And transfer of lessons learned. The company made significant improvements in IGCC design. When you live with that car day to day you learn it, and you know what makes it run better.

Equipment layout; materials of

construction; performance, heat rate; and how to start it up and get it going. Those improvements from Polk Power Station have been made available to EPRI's coal fleet for Tomorrow Program, so that all the members of the EPRI coal fleet program, those that are going to be looking at IGCC and planning IGCC plants right now have available to them all of these lessons learned from Polk Power Station and Wabash River.

So, in other words, for others that are looking at driving a hybrid car, now you've been able to talk to everybody else that has one; and learn how to make it work better; and what it's going to take to get down the highway, save on gas, and everything else.

The next generation of IGCC plants will benefit from nine years of experience with lower costs, better performance and higher availability. And that's what we need when we generate power.

As the sun rise, Polk Power Station, low emissions, low-cost feedstock and low-cost electricity.

Again, thanks for inviting me here. Appreciate talking with you. And I guess I've got some time for questions. Thanks.

PRESIDING MEMBER GEESMAN: Thanks very much, Steve. What proportion of your capital cost did the Synthetic Fuels Corporation cover?

MR. JENKINS: Well, it was Department of Energy Clean Coal Technology Program funded overall about 25 percent of the total cost of the plant.

In total, the gasification piece of the IGCC is about two-thirds. So you've got one-third that's the combined cycle plant, and the other is the gasification piece.

PRESIDING MEMBER GEESMAN: Who absorbed responsibility for cost overruns?

MR. JENKINS: I should tell you we didn't have any cost overruns.

PRESIDING MEMBER GEESMAN: You should, but that was going to be my next question.

MR. JENKINS: Yes. I would really say we didn't have cost overruns. What we did do is, as we were learning more about IGCC from Wabash River, as we were finalizing our design, we made some enhancements that did cost money. And DOE saw the benefit in funding some of those.

PRESIDING MEMBER GEESMAN: And you said that the gasifier was about two-third of your capital cost?

MR. JENKINS: Yes, of the total plant cost.

PRESIDING MEMBER GEESMAN: But in current design where they're talking about two or three gasifiers, that would be a smaller scale gasifier?

MR. JENKINS: Yes, you might use instead of one at 100 percent, you would use two at 50, or three at 50, that way you have 50 percent, you have a spare sitting there.

And we've had, over the years, obviously cost reductions in the gasification part of the plant. We know how to do it cheaper and better next time, in the next generation.

So adding that next gasifier doesn't mean that now it's more than two-thirds of the cost of the plant. Because that two-thirds piece, the gasification, gas cleanup and all the things that go with it have become less expensive because of the experiences at Wabash River and Polk.

UNIDENTIFIED SPEAKER: (inaudible).

MR. JENKINS: Yes, yes. Because this was 250 megawatt scale, you would use two of those for 500 megawatts to 600 megawatts scale. So, yes, about the same size.

PRESIDING MEMBER GEESMAN: Just from the sound of it, it sounds to me like the next generation of these plants are likely to be utility projects as opposed to merchant projects. Would you agree with that?

MR. JENKINS: Yes and no. And the reason I say that is there are a lot of the EPRI coal fleet members that are investor-owned utilities. And many of them are independent power producers.

We're actually doing the permitting for Excelsior Energies Mesaba Energy Project in northeastern Minnesota. They are an independent power producer and they are getting some cofunding under DOE's clean coal power initiative to build a second generation IGCC power plant.

PRESIDING MEMBER GEESMAN: Thanks very much.

MR. JENKINS: Thank you.

ASSOCIATE MEMBER BOYD: Having crawled all over Cool Water I didn't think I was going to have any questions for you, but the problems you had in the beginning, and recognizing this is a very significant scale-up, and a lot of years have passed, were you surprised in the first three years by the amount of difficulty you had? Or is it your typical R&D type, you don't know so you're not surprised?

MR. JENKINS: Well, actually the Polk Power Station was a little over twice the size of Cool Water. Cool Water was designed around, what, 1100 tons a day of coal and Polk was 2500. So not that much of a scale-up.

It was a tough three years, like I said. But on other technologies, for example when we started up our first flue gas sulfurization system the first two to three years of getting that running were tough. We hadn't seen one of these before. We could go visit other scrubbers. We could go look at other cars, but this was kind of a unique type of power plant.

We had people and visits to other plants. And we had the people who had worked at Cool Water to, like John McDaniel had said, here's what it's going to be like. And we used the lessons learned that we had to train our people and say, here's what you're likely to expect.

Again, with the simulator we knew what to expect, and how to fix those problems. But it was a tough three years. But we expected that.

This, although it was under the clean coal technology program, this was a baseload unit that was, after the R&D portion of the demonstration period was over, this plant had to run and make power for Tampa Electric's customers. It wasn't a two-year, let's see how this technology works, and then shut it down.

And nine years later it's operating. And, again, it's the cheapest, most efficient plant in the entire system for Tampa Electric.

ASSOCIATE MEMBER BOYD: Now my most burning question is how did you get that lump of coal through airport security? It looks like a piece of plastic explosive.

(Laughter.)

MR. JENKINS: You hide it under your laptop battery.

(Laughter.)

MR. JENKINS: No, actually it was in my pocket the whole time. And it even went through, you know, it was on me when I went through the screening, the little metal detector. There are metals in coal, but didn't pick those up. It's a fairly safe energy source.

PRESIDING MEMBER GEESMAN: Commissioner Pfannenstiel.

VICE CHAIRPERSON PFANNENSTIEL: What was the average cost of power at this plant last year?

MR. JENKINS: I asked John McDaniel that question and he said, I'm not going to tell you, but it was the cheapest on the Tampa electric system.

As I recall that would be somewhere, a total generation cost of somewhere around 3 to 4 cents per kilowatt hour.

VICE CHAIRPERSON PFANNENSTIEL: All right. And so I was going to ask you to compare that against the coal plant that is nearby, --

MR. JENKINS: Yes.

VICE CHAIRPERSON PFANNENSTIEL: -- the conventional coal plant. So that would be just something slightly higher than that, I assume?

MR. JENKINS: This uses a less expensive feedstock because coal is more expensive than this blend of petroleum coke and Venezuelan coal right now. And petcoke tends to be less expensive than coal.

So the feedstock cost is less. And the plant's more efficient. If you used the same feedstock in that pulverized coal unit 30 miles away, the overall plant would not be as efficient. And that's one of the selling points of IGCC. You take advantage of the efficiency of the combined cycle unit, and take advantage of being able to produce a low-cost syngas that feeds it.

If natural gas, I don't know what natural gas is going for today in California, $7 to $8, maybe $8.50 --

UNIDENTIFIED SPEAKER: Ten.

MR. JENKINS: Ten? It's a good day. And syngas is probably 35 to 40 percent of that. Which is why a lot of companies now that use natural gas on their combined cycle units are looking to refuel them by gasifying coal or petcoke. And get away from having to deal with day-to-day jumps in natural gas prices.

VICE CHAIRPERSON PFANNENSTIEL: Thank you.

PRESIDING MEMBER GEESMAN: Thanks, again, Steve.

MR. JENKINS: Thank you.

MS. MUELLER: Out next session is going to be on what are the challenges to building a clean coal plant in the western United States.

And we have three speakers here. I'm going to go ahead and introduce all three speakers, as we did this morning; ask them to sit over here at the table at the end of their presentation; and then we'll open it up for questions.

Our first speaker is Dr. Ashok Rao. He is the Chief Scientist for the Power Systems at the Advanced Power and Energy Program of the University of California at Irvine.

Dr. Rao has worked in the industry for about 30 years in the design and development of gasification, synthetic fuels and power cycle systems before taking a position at the University.

In his prior position he held the dual position of a Senior Fellow and Director in Process Engineering at Fluor Corporation. Prior to Fluor he had worked for gasification licensers.

Our second speaker will be DeLome Fair. She's a Product Line Leader for the gasification technology for GE Energy located in Houston. Ms. Fair has a masters degree in chemical engineering and has been working in gasification technology for 14 years with GE, Chevron Texaco and Texaco.

And our last speaker will be Kevin

Taugher. He is a Product Director for Alstom's utility boiler business headquartered in Windsor, Connecticut. In his 27 years with the company he has held a variety of positions in the Alstom Power business, including field design services, engineering and management in utility boilers, heat recovery steam generators and power services groups.

Dr. Rao.

DR. RAO: Good afternoon. The challenge is not so much whether clean coal technology is available, but what is the appropriate technology. Is it IGCC, or is it boiler. Then, within boiler you have at least a couple of choices. You have the PC boiler or the fluid bed.

Which technology results in the lower cost of electricity, while in environmental compliance consistent with a design basis. And if CO2 capture is required. The challenge is not really finding a technology suitable for capturing the CO2, but more in finding a home for the captured CO2.

So what really is required as one of the initial steps is to come up with a design criteria for this clean coal plant. Define the environmental criteria which answers how clean is clean. And along with the economic criteria, which is how much are you willing to pay for it.

Let me start out comparing IGCC versus the boiler. The answer is not simple. It primarily depends on the emission limits for a particular plant, but in addition to that, it's a coal type, the location, site-specific conditions all influence the relative economics of the IGCC performance costs versus a boiler plant.

As far as the rank of the coal goes, it has a significant influence on both the performance and cost. The ash content and its properties are another set of important parameters for the cost and performance of these plants.

For example, the ash fusion temperature under reducing conditions typically sets the gasifier operating temperature in case of slagging gasifiers. So, the performance and the refractory life, et cetera, are all very much dependent on what the ash fusion temperature under reducing conditions is. That's just one specific example.

Moisture content is another big influence on the performance. This is especially true for slurry-fed gasifiers.

Now, site-specific conditions are also very important as to how the two plants compare. Elevation, for example. The gas turbine performance is very much sensitive to the elevation. At higher elevations the capacity of the gas turbine reduces. And in the case of an IGCC the bulk of the power is produced by a gas turbine.

The availability of water, and typically mode of heat rejection, which goes hand in hand with that, has an influence also on the relative economics. IGCCs typically consume less water, about 70 percent that of PC boilers for a high rank coal. But if the plant has to be sited in a place where you have to install dry cooling towers, if dry cooling towers are not possible, then the degradation in the plant performance for an IGCC is a lot less significant, since the bulk of the power is produced by the gas turbine, which does not require any cooling water.

Now, if there is a market for the coproducts, such as hydrogen, then definitely an IGCC is going to have a big advantage. So, it's difficult to generalize which is better.

Costs are generally competitive for an

IGCC on higher ranked coals. And if you have a lower rank coal like PRB, as was mentioned earlier, this morning also, petcoke blending would be very beneficial.

And as you know, crude is getting heavier; it's metal content is increasing; sulfur content is increasing. So there's going to be a greater supply of petroleum in the future, and also it's going to be bigger challenge to get rid of this petroleum coke in the existing marketplace. So that could be a good opportunity to utilize that, and at the same time the lower rank coals in the IGCC applications.

And as I mentioned, coproduction is definitely an advantage for IGCC. It produces synthesis gas to start with. And if it's hydrogen, it's pretty much simply separating the hydrogen from the mixture, which is primarily CO and hydrogen. By the way, CO and hydrogen are building blocks for a host of chemicals you can produce including Fischer Tropsch liquids or synthetic diesel.

What I'm going to do next is spend a few minutes talking about IGCC technology's features; and then do the same thing with boilers before I conclude.

What's listed here is certain gasification technologies that are suitable for higher rank coals, and I've done the same thing with lower rank coals.

You have first the slurry-fed gasifier, the GE and the E-gas gasifiers, very suitable for high rank coals. But again, that can only be generalized. Previous studies, for example, looked at the performance cost of these gasifiers on Pittsburgh #8, Illinois #6 coals. Both are bituminous coals, but there's a significant difference in the cost and performance. So, it's very important that we know how these gasifiers will fare on a coal such as, say, Black Mesa or Utah bituminous, if those coals are of interest to us.

One thing I do want to mention, though, is that if the coal is going to be supplied as a slurry, which is being done, by the way, with Black Mesa coal being supplied from Arizona to a power plant in Nevada, that could be a natural fit for slurry-fed gasifiers like E-gas and GE gasifier.

Now, the Shell gasifier is also very

suitable for high rank coals except it tends to be more expensive. Design improvements are being made to reduce the cost. BGL gasifier, it's a highly efficient gasifier, suitable again for high rank coals. But it's very limited experience.

For the lower rank coals there's, of course, the Lurgi gasifier, been commercialized for a number of years now. In fact, a North Dakota gasification plant uses a battery of Lurgi gasifiers. The plant tends to be a bit complex because of the tars and oils production. And it can handle only a limited amount of fines. In fact, at the Dakota plant the fines are being burnt in a boiler.

Some of the other technologies to watch for, for low rank coals are the high-temperature Winkler and the advanced transport reactor, which was mentioned earlier. That's very promising technology, the ATR. In fact, I will also mention the plants for demonstrating this on a much larger scale. Currently it's operating at a scale of 50 tons per day in PDU.

Now, the timing of this project is very important. The future looks very good. One of the reasons is that the gasifier licenses are working very closely with engineering firms like Fluor, Bechtel, et cetera, in developing standard plant designs to reduce the engineering costs.

The other thing that's happening is the gas turbine technology is improving. The gas turbine firing temperature, as well as the technology within the gas turbine itself, in terms of cooling, incorporation of reheat combustors, et cetera. This will not only improve the performance of the IGCC, that is reduce the heat rate, but also reduce the capital cost.

Each time you improve the efficiency of the power block you end up downsizing the front end of the plant. You need that much less fuel to produce a kilowatt of power. And the bulk of the cost is associated really with the gasification plant. So you'll start seeing a reduction in the plant cost on a dollars per kilowatt basis.

This shows the efficiency trend that can be expected with more advanced gas turbines. You had the GE7-FA as the baseline here. In fact, this, itself, is outdated now. GE has now the 7-FB gas turbine which is more efficient, offered for IGCC applications.

But when you have the H machine, steam-cooled engine, that's offered for natural gas applications. When that's available for IGCC applications you can see there'll be a significant improvement in efficiency and a corresponding decreased in plant costs.

Now, more advanced combined cycles are being investigated. In fact, DOE is encouraging the development of these more advanced cycles. We're talking about 65 percent efficiency on natural gas basis. So with that you'll see about approximately 20 percent reduction in heat rate, or what you get with a 7FA gas turbine based IGCC.

Now, IGCCs have excellent environmental signature. Of course, a lot has been already stated. But let me just mention that sulfur is captured as a saleable byproduct. And going above 98 percent capture doesn't increase the cost very significantly.

A real advantage with IGCCs is in the heavy metals area. Commercially proven for capture of mercury, as well as arsenic; greater than 95 percent capture can be achieved. And this is done using a sulfided activated carbon bed. And the same bed is expected to capture other bad actors such as selenium and cadmium, which should be getting attention in the future.

And the incremental cost for capturing these heavy metals is not very significant. One of the reasons is that the amount of volume of gas that's treated is very small. You're dealing with the fuel gas or the syngas rather than the combustion products.

In the NOx area, gas turbine manufacturers are willing to guarantee 15 ppmV NOx. And you can go even lower, ultra low NOx, with the help of an SCR. And this has been installed in an IGCC facility in Japan. It's operating without any problems.

Particulate emissions data, which are very low, shown here are based on actual data collected at the Wabash IGCC.

Mention that water usage is much lower for IGCC. Of course, solid wastes, not only you have less production, but also it comes out in a slagging gasifier in the form of -- in a vitrified form, it's like lava rock, unleachable.

And, of course, a lot has been said already about the CO2 capture. It has a low incremental cost. What I mean by low incremental cost is when you're comparing an IGCC with CO2 capture versus an IGCC without CO_2 capture, the penalty of recovering the CO_2 is quite small. And the reason for that is, of course, you're dealing with recovering CO_2 from a gas that has a high partial pressure of CO_2.

And at the same time, the CO_2 is released at significantly higher pressure than atmospheric pressure. What that does is reduces the cost penalty as well as the performance penalty of compressing the CO_2 to the pipeline pressure.

One more thing I wanted to mention here is that, you know, the same acid gas removal unit that's required for capturing the sulfur is used for capturing the CO_2. Of course, you know, you have to add a few more columns and you're limited to a certain type of solvents. But the important thing is that you are not increasing the complexity of the plant significantly by going to CO_2 capture.

Next I want to spend a few minutes talking about boiler technology. You have the PC boiler, which has been used in super critical service for a number of years, for about 45 years now. It's a mature technology. Current availabilities are similar to subcritical units.

Typically lower plant cost than IGCC, especially for lower rank coals. But, again, a detailed analysis is required for these specific conditions, these specific conditions in terms of environmental criteria, site-specific conditions such as elevation, water and particular coal.

Moving on to fluid bed boilers, I understand the current max size is about 300 to 400 megawatts. And larger sizes are being investigated so that a super critical steam cycle can be incorporated.

One of the advantages with fluid bed boilers is, of course, the lower and uniform bed temperature which is helpful for the water wall enclosing the bed. The negative side, of course, having lower bed temperatures is that you have small delta Ts for heat transfer, increases the surface area within the bed.

Now, it's extremely fuel flexible. On one extreme it's applicable to brown coals, the other extreme applicable to the nonreactive anthracite coals. And because of the lower bed temperature it has better environmental characteristics as far as NOx emissions go. And sulfur is captured by injection of limestone or introducing limestone into the bed, along with the coal. And typically you can get as much as -- up to 98 percent capture.

Just like I showed for the IGCC case, the performance improvement to be expected in the future, similar things are going to happen with the boiler plant, also.

This shows the cycle efficiency for various steam cycle conditions. The current state of the art is about 40 to 100 psi, or 1100 degrees Fahrenheit superheat, reheat. And going from there to say about 1200 degrees superheat, reheat, 100 degree Fahrenheit increase in temperature, and a corresponding increase in pressure will give you quite a significant boost in efficiency.

And, in fact, the Europeans are developing the -- they have the Thermie project, which is going to take the superheat, reheat temperatures beyond 1200 degrees. They're talking about 1300 degrees Fahrenheit, which will increase the net efficiency of the power plant to greater than 45 percent on an HHV basis.

Now, as far as cleanup technologies go, the boiler people aren't keeping quiet. Their technology for cleanup is also evolving. I just included a few of the interesting, or some of the promising technologies here.

For FGD you have the Cansolv process. The beauty of this process is that it uses an amine solvent, and it captures the SO_2 and during regeneration releases the sulfur in the form of SO_2. So what you can do is make sulfuric acid with it, a saleable byproduct, rather than producing gypsum, a disposal problem.

For NOx you have BOC's LOTOX process. It uses ozone which is produced by oxidation of O_2 in the air using electric current. That, in turn, oxidizes the NOx to a soluble species which are then scrubbed out of the flue gas.

Now, each of these processes has advantages and disadvantages. One of the disadvantages with this process is that it uses a huge amount of power, your product that you're producing.

For particulates, there's the EPRI's COHPAC. It's a combination of ESP and baghouse. For mercury you have at least a couple of processes. Alstom has the Filsorption. And, again, EPRI has the TOXECON. This has been demonstrated on existing coal plants. Removes about 90 percent of the mercury.

And as far as CO2 capture goes, if that's required, then amine technology is offered by a number of licensors. It's been commercially practiced in plants where the flue gas is generated by, say, a gas turbine or the reformer exhaust. In each of these gases the fuel is really natural gas, and there's very limited experience on coal-derived flue gases.

So, to summarize what I've said so far, the answer is not simple for picking the appropriate technology. I believe clean coal technologies are available. IGCC is very clean. But the challenge is how much are we willing to pay for it.

And the necessary first steps I would think would be establishing a design criteria and perform a detailed techno-economic evaluation specifically for the coal or coals in question, the site, and the environmental constraints that are chosen for this clean coal project.

And then it's important to factor in the lessons learned into the conceptual design. Let's not reinvent the wheel. And compare the technologies on a consistent basis with similar commercial guarantees, experience with applicability to particular coals and its trace components. That's very important because it may be proven a certain type of technology, a control technology might be well proven on a certain type of coal, but we need to make certain that it works with our coal. Trace components can play havoc in certain technologies.

Also an important thing is to assess the commercial experience in integrated design. Like if you have two sets of control technologies, or two type of control technologies, each for a certain type of pollutant, you want to make sure that each is compatible with the other. If the downstream unit can process the effluent from the upstream unit.

I've seen horror stories where people have gone ahead and built megaplants and when the plant starts up they find out that some of components are incompatible with the upstream units. So all that needs to be investigated.

And with that, I conclude.

MS. FAIR: Move the stand a little bit so you can see my face. Talk about IGCC from

General Electric's perspective. We've -- a lot of the stuff I'm going to say has been said before, so I'll try to rush through that information and get to the new stuff.

A lot of coal generation in the world is -- power generation's from coal today, and a significant amount of new projects are being considered throughout the United States.

The utilities that are making these decisions on power generation, what are the market challenges they're facing. High volatile natural gas prices; and the availability of natural gas and LNG. Aging coal-fired fleets aggravate U.S. demand growth. Need for fuel diversity. Large percentage of all new generation in the past ten years has been natural gas.

Concerns over energy security. Wanting to use domestic resources of energy. Increasing environmental regulations, and carbon dioxide capture and management.

Trying to dig a little bit deeper into the gasification technology and IGCC. IGCC is a conglomeration of proven technologies into an integrated unit. Many of these technologies have been around for 50 or more years.

Coal grinding, talked about that. The coal is ground into a very fine powder and mixed with water to provide slurry. The air separation unit takes the air and separates it into oxygen and nitrogen in a cryogenic process. The oxygen is used in gasification and the nitrogen is used in the combined cycle to reduce the NOx emissions from the combustion turbines.

Gasification has been commercially used for over 50 years, primarily in the chemical industry, for the production of ammonia, methanol and oxychemicals. They're currently, between the three major technology providers, about 16 or 17 operating coal or petcoke gasification units in the world today. Some of those have been operating for over 20 years for the production of chemicals.

Gas cooling. The syngas has to be cooled down to about 100 degrees before the sulfur can be removed. So that's the gas cooling step.

Acid gas removal, there's several different technologies that can be used there. You can use an amine process similar to what's been described for flue gas treatment of CO2. You can also use a physical solvent such as selexall or Rectisol. All of these technologies have been used extensively in chemical and refining industries for years. And combined cycle power block, on natural gas is also a very proven technology.

So we're taking these technologies and putting them together, and that's been the challenge to the IGCC industry over the years, and to the utilities that want to put these plants in. They come in and they say, okay, if I want to build a gasification IGCC plant I have to select a gasification technology and make a deal with this guy. I have to go find an EPC contractor to build the plant. I have to select an ASU. I have to pick all these technologies and pull them together. And that's not something that they're used to doing or comfortable with doing.

What's emerging now in the IGCC industry is alliances of technology providers and engineering companies that are going to do all that for the utilities and provide a single point solution or a standard plant.

IGCC is cleaner by design. The syngas is treated to remove the constituents that would cause pollutants before combustion, so we're preventing the pollution versus cleaning it up from the flue gas. It's much more efficient and you're able to get much deeper removal because you're dealing with 1 percent of the volume of the gas, and it's also at high pressure.

The minerals, again, are melted in the gasifier and resolidified in a glassy vitreous state that's nonleachable and has commercial applications. Sulfur is converted to elemental sulfur and the removal of mercury is greater than 90 percent. We believe it's pretty near 100 percent, based on the experience of Eastman. They've been removing mercury from coal-generated syngas for over 20 years.

Some more emissions data. The advanced PC and SCPC, there's two sets of data here. The short bars are what we've seen just surveying the industry of what the best individual points are for each individual pollutant.

As far as I know there's not one plant that's currently being proposed that meets all of these limits. The taller bars are an average of 28 permits and applications of publicly reported documents over the last two or three years.

The IGCC bars represent what we're

currently designing for our reference plant design. As you see, that's getting very close to natural gas for SOx, NOx and particulate matter. And, again, mercury removal; and IGCC also uses less water typically.

CO2 production. The top two bars show the amount of CO2 produced per megawatt hour for coal at different efficiencies; 41 percent versus 45 percent. As you see from this, you know, small increases of efficiency are not going to have a huge impact on CO2 emissions.

Going down to the green bars, natural gas combined cycle produces less CO2 emissions, but still a significant amount. The bottom bar represents what could be achieved with a coal plant with carbon sequestration. And IGCC with sequestration, we believe to be the cheapest, the most economic option for achieving this.

How do you get the CO2 out of an IGCC facility. And what are the technologies that will be utilized. Again, this is a conglomeration of commercially proven technologies that have been used in the chemical and refining industries for 20 plus years.

The numbers of experience shown here are just the GE numbers. If you add in the other technology providers they go up quite a bit. We're combining gasification.

The second stage is called water/gas shift. That basically takes the carbon monoxide that's in the syngas and converts it into hydrogen. There's -- we have over 25 of our licensees that are using either syngas that's produced from either oil, petcoke or coal to produce -- and they shift the syngas into hydrogen for chemical production.

The next step is removing the CO2. Again, it's the same technology that you would use for the acid gas removal or the sulfur removal.

There's many plants today that use this technology to remove 100 percent of the CO2 from shifted syngas. This is in chemical applications. And they do that not to capture it and sequester it, but because it's a contaminant in their chemical process, and they just need to separate it and remove it. But they achieve 100 percent removal of CO2.

And then feeding that into the hydrogen then would go into a syngas turbine which then the emissions from that would be -- contain no carbon dioxide.

Gas turbine capability on hydrogen. It's limited with the size of turbines that we're talking about for IGCC. There is significant experience with gas turbines operating at 50 percent or more hydrogen. Smaller industrial turbines. GE has that experience. And the F class has had combustion validation in the lab up to 90 percent hydrogen.

Looking now at the cost of electricity. This is kind of our take on the cost of electricity impacts of IGCC versus pulverized coal. When GE bought the Chevron-Texaco technology we believe that the CapX premium for IGCC over SCPC was about 20 percent.

With research and product development when our launch project is announced and built, we expect that CapX difference to be cut in half and to be a 10 percent CapX premium. With an ultimate goal of driving to CapX parity.

At a 10 percent CapX premium if you add emissions credits for NOx and SOx and additional capital for mercury removal, to get the SCPC plant on an apples-and-apples basis with an IGCC plant on emissions, the cost of electricity is basically at parity. It's represented by the solid bars. As CO_2 has come into play, that CapX difference is apparent.

PRB, and we've got here on the corner here, we know that there's going to be a CapX premium right now with current technology. And we have programs in place to address that, and I'll talk a little bit more about that in a minute.

What's been holding IGCC back. If we look at the timeline at the top, you know, the Cool Water prototype was developed in mid '80s. About ten years later there are the commercial demos of Polk and Wabash and Buggenum. All about 250 megawatts.

There was not much activity in coal gasification in the next ten years primarily due to low natural gas prices and large investments in natural gas production.

Currently all the gasification technology providers are out there offering 600 megawatt or around that, 600 megawatt competitive commercial offerings.

The things that have kept IGCC down in the past, CapX too high; cost of electricity too high; poor initial availability; and a real big one is no system guarantees or warranties. The technology providers would provide a license and guarantee the gasifier, and the turbine providers would guarantee the turbine, but no one would guarantee the whole system.

The solution, the puzzle pieces are coming together, there's been technology consolidation. Alliances have been formed and are making commercial offerings. Single-point offering where the customer can deal with one entity and buy the entire IGCC plant.

There's also step increases in product development spending, process improvements and optimizations.

IGCC in the western U.S. The issues, you know, we expect a significant portion of new coal generation in the U.S. to use western coals. The bulk of gasification experience is on eastern bituminous coal and petcoke. IGCC is technically feasible on western coals, but the economics are currently unfavorable. Competitive solutions for western coals are needed. And combined cycle output decreases with altitude.

Some actions and some things that we're doing and others are doing, you know, as has been mentioned, I think, here today, IGCC with PRB and petcoke blends is ready today, and is a viable commercial solution.

For the long term, technology development for higher efficiency gasification of low rank coals is underway by GE. We expect to be able to make some commercial offerings on those improvements within the next couple of years.

Western coal demo plant and the Energy Policy Act of 2005 will accelerate commercial demonstration of low rank coals. And investigating mitigating actions to reduce the altitude impacts on combined cycle needs to be done, as well.

Just want to emphasize GE's corporate commitment to gasification IGCC. IGCC is one of the 17 initial ecomagination products that was announced by Jeff Immelt in Washington, D.C. earlier this year. A significant amount of money is being invested in the reference plant. We will, by the end of the year, double our head count in Houston. And we have over 200 technologists around the world developing new technologies and improving existing technologies.

We've increased development spending by

over 15 times, and are bringing IGCC gasification and syngas power island development into the long-term product development practices of GE that have been very successful in the past.

So, with that, I'll turn it over to whoever's next.

MR. TAUGHER: Good afternoon; my name's Kevin Taugher. I'm with Alstom Power. I'd like to thank the Commissioners and our fellow panelists and the concerned citizens that are here today.

I'd also like to thank Rich for the coveted last position on the presentation of the day. But that's okay, I can make it short because as I was hoping, most of the issues would be broached by the time it came to me. And also it would be clear that there's a wide spread of numbers on the different technologies, the different costs and the different issues confronting conventional coal versus clean coal.

And that's one of the things I'd like to talk about, is that conventional coal should very well be considered clean coal.

Sticking to the agenda, which had to deal with what are the challenges facing power generating in the western states, and I'm going to go through just a few items. We've talked about a lot of these things already, but plant site considerations, permits, financial drivers. I mean power plants don't get built without financing, and there's not too many banks that treat, you know, billion-dollar investments as a trivial matter.

Criteria pollutants and what can be done with conventional pulverized coal technology and other conventional coal technologies. Something that wasn't talked about, and that was opportunity to upgrade existing plants. And then, the CO_2.

I'm going to jump -- there's a little gremlin here in the slide order. But one thing I'd like to point out is that in the purple slide to the left, you know it's important to note that 39 percent of the coal-fired megawatts are greater than 35 years old. And that's a big issue when you start looking at, you know, performance and emissions and the permits on 35-year-old units and what they've been asked to do versus newer units.

You can also see the buildup of new units in the last 10 years has been almost nonexistent, and that's also one of the reasons behind that is the lack of firm regulations that people, investors and builders and engineering and power plant equipment providers can really bank on in order to put together a plant, as we heard earlier, that's going to last many years.

Another thing to talk about is when it comes to siting plants, of all the plants that are currently announced, they're all here in yellow, yellow stars. You see most of them are located on or near coal fields. There are a few over here that probably have access to rail lines and high voltage transmission lines that they're taking advantage of. But I'm not sure exactly that this really matches the real spread of the demand for coal-fired generation, or for that matter, electricity, going forward.

There's another issue is that with the total 336 gigawatt fleet, you know, incremental improvements in emissions within that fleet, be it CO_2 or the other criteria pollutants, should be considered.

Plant site considerations. There's a variety of things to be considered, of course. There's all these, they're just typical items. Transmission system, not only where you're near high voltage transmission lines, but whether or not you can interconnect and put a load at that point. Whether it's going to have impact upon the grid stability.

Coal availability. Same issues that we've talked about earlier, appropriate quality and a variable transport system. Available land, issue that comes up of greenfield versus brownfield. Can you put another plant at an existing site.

Constructability. One of the biggest issues we have now is the ability to build a plant with the right workers and the right skilled people to come in and do the welding and construction work. And, of course, parcel size is an important consideration. Everyone's aware of threatened and endangered species impacts.

We brought up also earlier today the potential for CO2 sequestration. How far can you transport CO2, say 100 bar, which is 1500 psi. I don't know if I want that -- there may be some people that may not want that going through their backyard.

Water supply and quantity. We've talked about that. And finally, approval and support from community and regulators. That's obviously one of the things that is the biggest issue for most of the -- any kind of power plant that's going to be built.

Typical permits, I'm not going to dwell on any of these. I'm sure people here could write this list longer than I could dream of.

But financial drivers, moving towards that. Environmental, obviously near zero emissions. And we've heard comments earlier today that near zero, even that has a range.

Economics, we got to use all the coal. I mean we're talking about coal throughout the U.S. as being 258-year supply, but it also means we're using all of it, not just a portion of it. We have to think about competitive ways we can convert coal into usable energy.

And then also something else financiers look at is a track record of performance. Do you have the track record that you can make things happen and get something financed in a conventional way.

Operations perspective. You need high reliability and commercial availability. That means it's there not only when you think the load is needed, but also when there could be upsets in the system where you need to have it ready to go. Includes being in the ability to go full load rated capacity, to go down to low loads without coming offline, to have spinning reserve. Things of those issues, with still making your emissions requirements and not having impacts on efficiency.

And finally the operating parameters appropriate for grid-based generation. Can you change the load; can you swing up and down in load; how quick can you respond to system upsets; things of that nature are very important for most system operators to be considering in conventional power plants.

Now, when we get to the issue on the emissions capabilities of conventional plants, I'd like to point out that over the last 15 years these are the actual emissions that have been, from the EPA, in spite of what we've seen, and this was brought up in an earlier presentation, that the increase in coal-fired generation is going up. The actual gross emissions are dropping. And that's the relationship between the change in regulations, the ability of plant operators to meet those new requirements, the ability of them to choose and select which ones they can do it most economically at.

But it's not a hoax. The overall emissions has dropped. And this is on that fleet of coal-fired units that includes 39 percent that are older than 35 years old.

When we look at the top 20, this is 2004 emissions data, the top 20 lowest sulfur emitters, you can see the light blue. Believe it or not are bituminous PC. The blue-and-white striped are sub-bit PC. CFBs show up down below for NOx emitters. And then you've got, there's one of the IGCC units is on the list for lowest SO2 emitters.

For NOx you see a similar story. Obviously the IGCC full capability comes up to scale. But believe it or not, it's still in the mix of units that have -- existing units, not new units, that have the ability to meet low emissions which are much lower than their permits.

Another issue for finance consideration is availability and performance capability. This is numbers from NERC. We've broken out between sub critical and super critical. There's been a tradition of super critical plants having lower availabilities, but it's really improved, particularly into the mid '90s where we used more advanced techniques and advanced controls that keep the units online.

Because there's an inherent operating characteristics of super critical units to make them less -- more susceptible to implications on taking offline on a rapid load change, it's been sorting out with better controls.

I'd still like to point out though that even though this difference here is maybe a percent or so, there are operating people that still believe 1 percent less availability means one or two more outages a year, which they don't want to deal with. So, that's another issue we have to contend with, even at 93 percent availabilities.

Another contentious slide, but in terms of the cost. And I'll point out a little somewhat sleight of hand, but nevertheless, IGCC actual costs, we're not talking about what we want them to be, but just the information we have available showing what the actual costs are across all IGCC plants. And then some realistic numbers from in terms of current new CFEs, projected ultra super critical PCs, actual super critical PCs and you see it right down the line.

Finally, just for comparison purposes, some of the least cost option for better, lower emissions and maybe even operating, might be to go back and retrofit existing units.

This slide just covers the issues that over the timeline of how conventional coal-fired power has moved from the '50s up to today. And then the future, is increasing the cycle performance, meaning higher pressures and temperatures.

Basically the bottomline is the more energy you can impart on a pound of steam before it reaches the condenser, the more efficient your plant's going to be. That's a little simple thermodynamic lesson. And that's what's driving the high numbers as a goal for these high efficiency units.

I would like to point out that in 1954 Alstom predecessor company, Combustion Engineering, actually sold the unit, and it's operating to this day, Eddystone I, that had conditions of 5200 psi design, 1200 degrees super heat, and double reheat 1050 and 1050. Currently that unit operates at 4700 psi, 1135 degrees, 1050/1050. The derate on temperature because the types of materials used did not anticipate some of the corrosive effects of the coals that were going to be fired. So not bad for 1954, but nevertheless, that plant is still running today.

We also point out that the change in efficiencies that were projected from current operation to potential going forward clearly indicate that all technologies are considering those moves.

The CO2 challenge. I won't belabor this, either, but obviously we believe if you minimize production through efficiency you can definitely cut your CO2 emissions proportionate with the increase in efficiencies.

We're looking into, as well as others, in developing different solutions. Our cost target within the next three to ten years, three to seven years, is to have a capture capability of $10 a ton for CO2.

Disposal issues. There's why there's question marks. A little busy slide, but just to give you an example of the efficiency implications. Call your attention to the lower left corner. The existing coal fleet average efficiency is 33 percent. That's of those 300-some-odd gigawatts of generation.

We can see that if we start here with your traditional subcritical PC plant and work your way up towards higher efficiencies, you can get inherent reduction in CO_2 output compared to your subcritical plant here. You can also see the CO_2 emissions coming down concurrently. There's another dotted line for people considering biomass, that at 10 percent cofiring biomass drops it even more.

To put a dot on this table in where the current research is heading is this 45 percent, which is common with both what the Europeans are doing, and what the U.S.A. Ultra Super Critical Material Consortium is doing.

And longer term, they're looking for the higher numbers, 46 to 48 percent, like we mentioned with much higher grade materials.

In summary, we believe that economically acceptable options will require that we have low long-term operating costs by having an abundance of the right coal reserves in play for making power.

Obviously proven reliable and economical

PC and CFB technologies. Minimize risks for both capital and operating considerations. PC and CFBs have demonstrated, underscore the word demonstrated, because right now they do seem to be leading the pack, on emissions.

And it's not sitting there. We're moving forward with strategies to improve upon those, as well. But as clearly mentioned earlier, if you look at the improvements in emissions, they're all tied back to regulations that have been identified and enacted and moved forward. And I think that as that happens we'll see that the status of the conventional coal-fired plants improves.

Obviously, as we've heard, the CO2 ready, it can be stated for conventional pulverized coal. And the only plug of the day, it's conventional advanced coal combustion is still the viable technology for clean power.

Thank you.

MS. MUELLER: Do the Commissioners have any questions for our speakers?

PRESIDING MEMBER GEESMAN: Yeah. I have a couple. First, while you're sitting down, Kevin, you mentioned the prospect of retrofitting existing plants as possibly an attractive strategy. Retrofitting with what?

MR. TAUGHER: Yes. Some of the plants have installed SCRs. Anyone that -- any plants that own the latest low NOx burner technology can be considered.

We've done a number of projects where we've assisted plants in converting from high sulfur fuels to lower sulfur fuels. It takes changes to the boiler.

We've done a number of efforts with replacing the steam path and the steam turbine, which increases the efficiency from what the plant's currently running at.

Those are the kinds of options that can increase your rating and reduce emissions at the same time.

PRESIDING MEMBER GEESMAN: And then both of the first speakers reiterated what had been said this morning about the attractiveness of blending petroleum coke with some of the lower rank western coals. I wonder if either or both of you might address what type of blend. How much petroleum coke?

DR. RAO: Based on some of the work that

we did at Fluor when I was still employed -- when I was working with them. And that what used to be Chevron Texaco gasification then.

And we looked at western Canadian coal, very similar to PRB. And what we found is that if you had a 50/50 blend between petroleum coke and PRB, would be very similar to a high rank, a very good bituminous coal in terms of performance, oxygen consumption, et cetera.

PRESIDING MEMBER GEESMAN: And with that much petroleum coke involved, you'd have to transport it overland a fairly lengthy distance, would you not?

DR. RAO: You know, sending it by pipeline shouldn't be ruled out, especially for slurry-fed gasifiers, would be a good fit.

PRESIDING MEMBER GEESMAN: What's that do to your cost assumptions? How far could you transport by pipeline?

DR. RAO: Currently coal is being transported from Arizona, the Black Mesa, to a power plant in Nevada. I'm not quite sure what the distances are, but it's not totally unthinkable.

PRESIDING MEMBER GEESMAN: That you

transport the coal, not the petroleum coke?

DR. RAO: Petroleum coke, but, you know, in the form of a slurry should be possible.

PRESIDING MEMBER GEESMAN: Okay, thank you.

ASSOCIATE MEMBER BOYD: You got all my questions, except the biomass.

PRESIDING MEMBER GEESMAN: That's what 52 days of hearings is going to do to you.

ASSOCIATE MEMBER BOYD: Yeah. And it's really not a question, or maybe it is in terms of just how much biomass cofiring experimentation has gone on? I mean we heard about it earlier this morning, and I really haven't followed this too closely because we haven't followed coal all that closely of late.

But I'm, as indicated this morning, quite intrigued with that, and I'm hearing if referenced more and more. And I'm just wondering if somebody can give me an idea of how much experimentation has gone on with biomass.

I was intrigued by the emission reductions, obviously, in one of those last charts.

MS. FAIR: I don't really know exactly.

I'm thinking it's probably in the order of magnitude of 5 to 10 percent of the total feedstock, you know, the commercial unit demonstrations that have been done with the oxygen blown gasification technologies.

ASSOCIATE MEMBER BOYD: And I guess, observation, technology forcing through regulations still lives, according to the last speaker. So, I'm glad to see that, since I'm an old graduate of that school. I have no other questions.

MR. TAUGHER: Just a followup, too, for pulverized coal units, typically you can add up to about 10 percent by heat input. But you have to worry about the ashutectics, if there's a lot of calcium or other elements in the biomass that may present issues with the ashutectics of the coal it can lead to slagging problems.

But we have a couple projects in Europe, Alstom does, where, you know, they've made permits for coal-fired units that can only operate if they incorporate biomass and things like palm kernels and olive pits, things like that is some of the stuff they're considering burning, or actually burning in the Netherlands and the U.K.

That brings up another issue. I don't know there's too many indigenous olive trees in the U.K., but they're getting them from somewhere and burning them for the permit, so I wouldn't necessarily want to do a CO2 analysis on that if you included the transportation of the olive pits from wherever into the U.K. But that's part of the point of the regulations is that was the hook for permit.

ASSOCIATE MEMBER BOYD: Another vote for full fuel cycle analysis, or well-to-wheels or call it what you want.

DR. RAO: I'd just like to add one comment to co-feeding or gasifying biomass along with coal. One option could be to dedicate a gasifier to biomass, a separate gasifier that's suitable for biomass, rather than blending it with coal.

This way you can have a much higher proportion of biomass going to the plant. And you have a gasifier that's designed to maximize the performance of gasifying biomass.

Then downstream of that you can always combine it and take advantage of the economies of scale for a larger plant.

PRESIDING MEMBER GEESMAN: Why don't we give the audience an opportunity to ask questions, either of this panel or any of the earlier speakers that we heard today, most of whom I think are still in the room.

Any questions from the audience?

ASSOCIATE MEMBER BOYD: I think there's --

PRESIDING MEMBER GEESMAN: Do we have anybody on the telephone that cares to ask a question?

John. Why don't you come up and use the microphone so we can pick you up on the transcript. Just sit down at the table and push the button on your mike so that the green light comes on.

MR. GALLOWAY: So after all these years I think I'm finally getting familiar with the Commission's technology.

Actually I had a really quick question, I may have missed something this morning. There's sort of this notion of renewables being paired with coal technologies on the wire, as it were.

So, in other words, if you're going to put renewables on the wire you pair it with a technology like IGCC.

And so there's this notion of like a firming and shaping that happens with, let's say, wind, if California were to import wind from Wyoming, for example, or Montana or wherever else outside the state.

And this is kind of a new concept to me that you can then use IGCC, because it's basically a gas turbine, to fill in, basically fill in the gaps on that product.

And it kind of struck me as odd that you basically can ramp the gas turbine up and down that much to match wind. And I'm just wondering, does that create any problems with mechanical stress on the system. You know, I had this awful flashback earlier this morning to the energy crisis, you know, this idea of rubber-banding and gas turbines.

And that, I don't think, was explained, or at least I didn't sort of get the explanation of how that would work, and how you pair the two. You know, that came up in Steve's presentation this morning, that you know, we really need to sort of pair the idea of renewables and coal and IGCC. And I'm just wanting someone to maybe explain how that happens technically.

PRESIDING MEMBER GEESMAN: I guess I'd add to that the question from a financial standpoint, why would the plant owner want to do that.

MR. GALLOWAY: Very good question.

PRESIDING MEMBER GEESMAN: But if there are any takers, these plants, as I've heard them described today, aren't really intended as load following plants. They're designed, as I understand it, largely for baseload purposes.

UNIDENTIFIED SPEAKER: Any takers?

MR. DALTON: I'll take a shot at it. Among other things, we've developed databases on a lot of the biomass cofiring done on pulverized coal plants around the world as part of our work over the last 20 years.

But, specifically on IGCC plants, you really don't normally want to run them down more than about 20, 30 percent of their load. So, indeed, if you try to take them all the way down to follow exactly and match exactly, you do have some issues.

However, you can coproduce, say, a stream of something like methanol. Tanks are cheap. You can put it in a tank and use that in a separately fired, for instance, simple cycle gas turbine or combined cycle that is fired specifically to match up.

Now, there are several combinations you could do on this. You can certainly take the top part of the load and help match it. You're not going to go all the way deep into the load cycle past about 20 to 30 percent to try and match the load with an IGCC plant.

Now, on the financial basis, I'm not sure why you'd do it, either, exactly that way. But what you could sell is basically a combined product. And you could sell it into the line. And it gives you more reliably available power on the line from the baseload generation.

So, yes, you have the top of the line covered in effect by some of the variation in the wind. And that could help in that area.

So far we don't have a good way to store electricity.

PRESIDING MEMBER GEESMAN: Thank you, Stuart. Other questions? Bill.

DR. RAO: Let me just add one comment to this non-baseload operation of IGCC. You know, it's the heat exchanges that are really the bottleneck. You know, you develop thermal stresses.

And combined cycles, by the way, of natural gas are being operated because of the high cost of natural gas, for intermediate load, turning them on in the morning, shutting them off in the evening.

And, of course, each of the heat recovery steam generator, which is behind the gas turbine, has given problems, but we have come up with solutions for designing the heat recovery equipment that can withstand higher thermal stresses.

And so, it is possible for an IGCC to have load swings in power while you divert the syngas for chemicals production or whatever.

MS. FAIR: And just one more point. Our customers are telling us that they don't want these IGCC plants to be baseload. They want them to be able to be -- to turn down at night, turned down on weekends. So that is something that we're developing into our designs, is that capability.

Just one more, to the reason why --

PRESIDING MEMBER GEESMAN: Can I ask

there, --

MS. FAIR: Yes.

PRESIDING MEMBER GEESMAN: -- are those utility customers or merchant customers?

MS. FAIR: Utility customers.

PRESIDING MEMBER GEESMAN: Okay.

MS. FAIR: The one option with the methanol, there's been talk about the spare gasifier, whether a spare gasifier is needed or not. If you did co-produce methanol and stored that, that could become your backup fuel potentially for the gas turbine. And completely eliminate the dependence on natural gas without the spare gasifier. So that's another economic reason.

PRESIDING MEMBER GEESMAN: I see John Galloway coming back to the microphone. But, Bill, why don't you come up and get a microphone, as well.

ASSOCIATE MEMBER BOYD: Nuclear, coal and now methanol have been mentioned in this room all in one week. Ancient subjects.

(Laughter.)

MR. KEESE: Commissioners, you've done a marvelous job in this hearing today with the broad spectrum. The question I have, I guess, I've heard IGCC for the production of fuels. And I've heard IGCC for the production of electricity. And they seem to be on separate tracks here.

I guess I have a couple questions, one of which is where is IGCC most likely to be economically appropriate? In the fuels first? Or in the electricity generation first? Or is the suggestion that perhaps we will have plants that will operate 24/7 and produce fuels part of the time, and generate electricity part of the time?

I haven't seen a convergence there. And I just ask the question.

MS. FAIR: I can give you my personal opinion. There's people developing projects on parallel paths and looking at both uses for gasification very seriously.

I think electricity, IGCC for electricity probably will happen first, just in that's already been demonstrated. It's a little bit further down the commercial path.

The Fischer Tropsch technology that converts the syngas into the fuels has only been demonstrated on, you know, very small scales. There's several technologies that haven't been demonstrated commercially at all.

So, with the exception of South Africa, where they're doing it en masse, the projects that I'm aware of that are being developed today in the U.S. are looking not with the technology that was used in South Africa, but with other Fischer Tropsch technologies that are not commercially proven.

And so those tend to take a little bit longer to get through all the checks and balances.

MR. KEESE: Did I hear correctly that in China, of the 100 plants that are operating, 10 are IGCC and they're going towards liquids? Is that what --

MS. FAIR: No, no, there's no -- the plants that are being built, the gasification plants that are being built in China are for the production of ammonia, ammonia and methanol and chemicals, not for power yet.

MR. KEESE: Thank you. I will see you again tomorrow.

PRESIDING MEMBER GEESMAN: We'll look forward to it. Welcome back to the hearing room.

Questions? I don't have any blue cards. Are there any members of the audience that care to address us? Must be a happy group.

Anybody on the telephone that cares to address us?

Okay, we're going to get out a little bit early then today. I thank you all for attending, and hope to see all of you tomorrow morning. Thank you very much.

(Whereupon, at 4:30 p.m., the workshop was adjourned, to reconvene at 9:00 a.m., Thursday, August 18, 2005, at this same location.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 21st day of August, 2005.